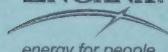


AR90

ENCANA CORPORATION annual report 2008

SUCCESS
BELONGS TO THOSE
WHO SEE THE FUTURE
BEFORE IT BECOMES

ENCAN

energy for people

BELONGS TO THOSE
WHO SEE THE FUTURE
BEFORE IT BECOMES

OBVIOUS

OBVIOUS

SUCCESS BELONGS TO THOSE WHO SEE THE FUTURE BEFORE IT BECOMES OBVIOUS

WHY OWN ENCANA?

We are a leading North American unconventional natural gas and integrated oil company headquartered in Calgary, Alberta. More than 80 percent of our production is clean burning natural gas. We are also a technical and cost leader in the recovery of oil through steam-assisted gravity drainage (SAGD). One hundred percent of our oil production is fully integrated with our two refineries in the United States.

EnCana represents a unique investment opportunity built upon predictable, low-risk, low-cost production growth from resource plays. Our value-driven and innovative business strategy is underpinned by our high-quality assets and reinforced by our strong financial position, which is guided by prudent risk management practices. This approach provides us with the flexibility to adapt to changing circumstances in these uncertain times.

Natural gas and oil resource plays are our strategic focus. With nine key natural gas and four key oil resource plays in Canada and the United States we are able to invest for the long term and apply continuous improvements to all areas of our business.



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FOCUSED ON CREATING SUSTAINABLE VALUE FOR SHAREHOLDERS

Developing unparalleled asset base to unlock underlying value

- Portfolio of established resource plays capable of sustainable long-term production growth
- Average daily production of **4.6 billion** cubic feet equivalent (more than 80 percent of which is natural gas) in 2008
- **23 million** net acres in North America with significant positions in several emerging resource plays such as the Montney and Horn River in British Columbia, Haynesville in Louisiana and Texas, and Deep Bossier in Texas
- **19.7 trillion** cubic feet equivalent proved reserves
- Drilling inventory of approximately **10 years**

Exercising financial discipline and flexibility allowing us to respond to changing market conditions

- Strong balance sheet
 - Debt to capitalization of **28 percent**
 - Debt to adjusted EBITDA of **0.7 times**
- Robust project returns – target risk-adjusted internal rate of return greater than **15 percent**, after tax

Returning value to shareholders

- Free cash flow supports an attractive dividend and flexible share purchase program
 - **\$1.2 billion** returned to shareholders through dividends in 2008
 - Since 2002, purchased about **270 million** shares, or 29 percent of shares outstanding*

EnCana reports in U.S. dollars unless otherwise noted and follows U.S. protocols, which report production, sales and reserves on an after-royalties basis.

Advisory Certain information regarding the Company and its subsidiaries set forth in this document, including management's assessment of the Company's future plans and operations, may constitute forward-looking statements or forward-looking information under applicable securities laws and necessarily involve risks and uncertainties associated with future events. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements or information. For further details see the Advisory on page 67 of this document.

This document contains references to measures commonly referred to as non-GAAP measures, such as cash flow, cash flow from continuing operations, cash flow per share – diluted, free cash flow, operating earnings, operating earnings from continuing operations, operating earnings per share – diluted, adjusted EBITDA, debt, net debt, and capitalization. Additional disclosure relating to these measures is set forth on page 70 in the Advisory.

*Based on shares outstanding as of December 31, 2002, and adjusted for 2 for 1 share split in 2005.

VAST LAND POSITION

23
million

net acres in North America

LARGEST NATURAL GAS PRODUCER IN NORTH AMERICA

3.8
billion

cubic feet per day

SUBSTANTIAL PROVED RESERVES

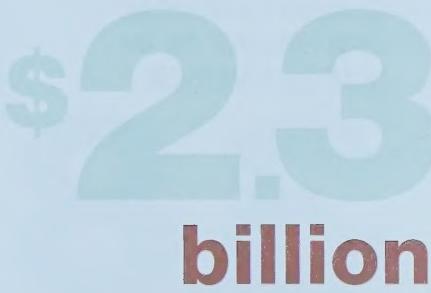
19.7
trillion

cubic feet equivalent

CEO'S MESSAGE

2008 will be remembered as a financial and economic rollercoaster. Oil prices shot from \$100 per barrel to record highs above \$145 then fell below \$35. Natural gas prices climbed above \$13 by mid-year before sliding well below \$6 per thousand cubic feet. The stock market tumbled by one-third. Companies everywhere faced unforeseen challenges. Rarely has so much changed so quickly. Through the volatility of 2008, EnCana achieved exceptional operational and financial performance, meeting or exceeding targets for production growth, cash flow and capital spending. We continued to achieve sustainable value creation in the development of unconventional natural gas and oil resources in North America. And of vital importance today, we are very well positioned to withstand the financial and economic challenges in 2009 and beyond.

NATURAL GAS GROWTH AVERAGES 8%



In 2008, EnCana's natural gas production growth averaged 8 percent to 3.8 billion cubic feet per day, driven by a year-over-year increase of 14 percent from our natural gas key resource plays across North America. Total 2008 natural gas and oil production increased 6 percent. Our strong gas growth was led by our East Texas resource play, up more than 130 percent, reflecting production increases and a doubling of our ownership interest in the prolific Deep Bossier formation in late 2007. Production from the company's Bighorn resource play in the deep basin of Alberta grew dramatically, up 33 percent, and our Cutbank Ridge resource play, home to our promising Montney assets in British Columbia, performed extremely well, increasing 15 percent.

free cash flow in 2008. Free cash flow can be used to pay dividends, buy back shares, and reduce debt.

INTEGRATED OIL DEVELOPMENT CONTINUES ON PACE

Our integrated oil initiatives continued to provide a steady pace of growth as 2008 production from Foster Creek and Christina Lake increased about 13 percent to average about 30,000 barrels per day. Current upstream expansions are setting the stage for continued growth with production expected to average more than 40,000 barrels per day in 2009. Our Integrated Oil Division generated operating cash flow of about \$375 million in 2008, down about 75 percent from 2007 levels. We reported a loss in operating cash flow of \$241 million from our downstream operations in 2008 versus

positive operating cash flow of \$1.1 billion in 2007. The 2008 loss was due to a dramatic drop in crack spreads and low year-end crude oil and refined product prices compared to 2007. At the Wood River Refinery, we received regulatory approval and began construction of our coker and refinery expansion (CORE) project. When completed in 2011, the project is expected to more than double heavy oil refining capacity to 240,000 barrels per day. Together, our Wood River and Borger refineries have sufficient capacity to integrate our total oil production.

CORPORATE RESULTS REMAIN STRONG

Stronger average commodity prices in 2008 were reflected in our cash flow of \$9.4 billion, or \$12.48 per share, up 13 percent, and operating earnings of \$4.4 billion, or \$5.86 per share, up 9 percent. Our \$7.1 billion of capital investment increased 17 percent, and we generated \$2.3 billion in free cash flow. Our 2008 proved reserves additions continued to be strong – replacing 150 percent of production at a highly-competitive finding and development cost of \$2.50 per thousand cubic feet equivalent. Total proved reserves grew 5 percent to 19.7 trillion cubic feet equivalent – resulting in a reserve life of about 12 years at 2008 production levels.

Our strong financial and operational performance occurred during a year that saw markets take an unprecedented move downwards. In 2008, EnCana outperformed the market, delivering a total shareholder return that was down a relatively modest 14 percent on the TSX in Canadian dollars compared to the TSX Composite Index, which was down 33 percent. On the NYSE, EnCana's shareholder return was down 30 percent in U.S. dollars compared to the S&P 500 Index, which declined approximately 37 percent. EnCana paid an annualized dividend of \$1.60 per share, which offered investors a 3.4 percent yield based on the year-end closing price of \$46.48 on the NYSE.

CORPORATE REORGANIZATION ANNOUNCED

In May, we announced a planned corporate reorganization that would split the company into two independent companies focused on distinct businesses – one unconventional natural gas, the other integrated oil. This transaction was designed to enhance long-term value for EnCana shareholders by creating two highly sustainable, independent entities, each with an ability to pursue and achieve greater success by employing operational strategies best suited to its unique assets and business plans. Extensive preparations were undertaken as we worked toward completing the transaction for a scheduled closing date in early 2009. However, intense uncertainty in global financial markets during the fall caused us to delay these plans until clear signs of stability return, at which time we will reassess our plans as we continue to pursue strategies that enhance the value of every EnCana share.

We are very well positioned to withstand the financial and economic challenges in 2009 and beyond.



Randy Eresman,
President & Chief Executive Officer

SHALE GAS EMERGES

This past year, the North American energy industry saw the widespread emergence of technical and commercial success from a variety of natural gas shale reservoirs. In 2008, we added to our extensive new shale gas resources, solidifying a leading presence in two of the most exciting shale plays in North America: approximately 435,000 net acres in the Haynesville Shale play centred in Louisiana and Texas, and about 260,000 net acres in the Horn River Shale play in northeast British Columbia. Both shale plays are at an early stage of development and the resource potential of these opportunities is enormous. Given the promising production performance we achieved from a handful of wells in 2008, and the extent of the shale, we expect both of these plays will become major sources of natural gas production in North America.

HIGH-QUALITY ASSETS AND STRONG RETURNS DISTINGUISH ENCANA

The current worldwide economic downturn is different from anything we have known in our lifetimes and most certainly since the creation of EnCana. While we are not able to predict the depth and duration of the economic turmoil, I believe EnCana will distinguish itself in 2009 and beyond for its resilient business model, financial strength, high-quality assets, operational excellence and capacity to continually build value from its core strength – vision, innovation and leadership in the development of unconventional resources. This is because our North American resource plays have the capability

to generate strong returns from predictable, low-risk assets at a cost that is among the lowest in industry. We have a high-quality and diverse asset base from British Columbia to Texas, which gives us the flexibility to narrow our investment focus to our best-return projects during low-price periods. We also have relatively few long-term capital commitments, further enabling us to reduce activity as necessary. Financially, EnCana maintains a strong and conservatively managed balance sheet, and an active

Our North American resource plays have the capability to generate strong returns from predictable, low-risk assets at a cost that is among the lowest in industry.

hedging program that has about two-thirds of our expected natural gas production hedged at a price of more than \$9 per thousand cubic feet until the end of October 2009. Financial strength and risk management are core EnCana business values as outlined on page 6 by Brian Ferguson, EnCana's Chief Financial Officer.

CONSERVATIVE, PRUDENT CAPITAL INVESTMENT

In 2009, we are taking a number of measures to enhance our resilience. Our capital investment program is conservative and flexible, allowing us to increase or trim capital investment depending upon how the year unfolds. We currently plan to hold production flat as we continue to invest in multi-year projects that are expected to deliver long-term value, such as Deep Panuke offshore Nova Scotia and the CORE project at Wood River. Management and staff have been conducting extensive reviews of capital projects and applying higher financial hurdles and screening filters to help maintain our financial and operating strength through 2009 and beyond. We are targeting a 10 percent reduction in capital investment and operating costs from the levels that we set in our 2009 budget. We have also frozen hiring and most salaries for 2009. We continue to seek opportunities to sell non-core assets,

provided sale prices meet our expectations, and we will continue to look for hedging opportunities. Operationally, our continuous improvement practices are being stepped up to help ensure we capture new efficiencies and find better ways to achieve our goals – operational improvements that can be shared across the company. While we are intensely focused on costs and optimal performance, we are equally dedicated to maintaining a safe and healthy workplace, operating in an environmentally responsible manner and continuing to play a beneficial role in the communities where we live and operate.

For the third year in a row, EnCana has been listed on two Dow Jones Sustainability Indexes (DJSI): DJSI World and DJSI North America. The DJSI family of indexes tracks the financial performance of companies that are recognized as global leaders in economic, environmental and social performance, as evaluated by an independent agency, Sustainability Asset Management (SAM). Our inclusion to the DJSI World Index means that we are recognized for being among the top 10 percent of the 2,500 largest companies worldwide in terms of a commitment to the principles of sustainable development. We intend to continue to pursue sustainable practices in the development and production of natural gas and oil for North American consumers.

The theme of this annual report is about success belonging to those companies that see where the future of their business needs to be, before it becomes obvious to everyone else. Many times we have said we believe the future of natural gas and oil development in North America is unconventional, which increasingly became our focus since EnCana's creation in 2002. On the following pages of this report you will find detailed descriptions of innovations, technologies, operational practices, business approaches, and employee programs that we believe will help make it possible for us to engineer value creation from unconventional resources. This is the culture of EnCana – continuous improvement to turn unconventional possibilities into leading achievement.

On behalf of EnCana, I want to thank the members of our Board of Directors for their ongoing skillful guidance and wise leadership as we continually strive towards building the leading unconventional natural gas and oil company in North America. And, I want to again recognize and thank our employees and contractors for an outstanding year of operational and financial excellence. As we look to the rest of 2009 and beyond, our steadfast focus remains on working safely, acting responsibly and enhancing the value of every EnCana share as we provide energy for people.



Randy Eresman
President & Chief Executive Officer

March 5, 2009



EnCana is ranked in the top 10% of companies on the Dow Jones Sustainability Index.

CFO'S Q&A

Maintaining financial strength; Managing risk in a volatile environment

Q HOW IS ENCANA POSITIONED TO HANDLE THE ECONOMIC UNCERTAINTY?

EnCana is facing the current economic climate from a very solid financial position. We have been building our North American portfolio of low-cost, low-risk, predictable assets, fine-tuning our approach to resource development and establishing strength and flexibility in our balance sheet for years. That discipline is paying off now more than ever. We have deliberately chosen a more measured approach to our 2009 capital program with a continued emphasis on generating free cash flow. With our disciplined approach to capital spending and a strong hedging program to support our cash flow requirements, we have the flexibility in both our development program and balance sheet to help us deal with the turbulent conditions ahead.

At EnCana we are confident that we have prepared ourselves to emerge from this environment operationally strong, with the integrity of our balance sheet intact and we expect to be well positioned to respond quickly when the business environment improves.

Q AS CFO, WHAT METRICS DO YOU FOCUS ON TO MANAGE ENCANA'S FINANCIAL HEALTH?

We use several metrics to test the resiliency of our balance sheet. They include debt to capitalization, which measures the percentage of total invested capital funded by debt. We target this metric to be in the range of 30 to 40 percent. At the end of 2008, we achieved a lower debt leveraged result with a ratio of 28 percent. We look at debt to adjusted EBITDA ratio as a measure to indicate, on an annualized basis, how long it would take if we applied our most recent year's EBITDA to repay our current level of debt. Our debt to adjusted EBITDA ratio at year end was 0.7 years. Lastly, we target our expected after-tax cash flow to exceed our forecast capital investment, which we refer to as free cash flow. Generating free cash flow improves financial liquidity.

Q HOW DOES ENCANA FUND ITS CAPITAL PROGRAM IN THIS VOLATILE ENVIRONMENT?

One of EnCana's business objectives is to have a capital investment program that is self-funding using cash flow from existing operations. Between 2002 and 2008, EnCana has been able to grow its cash flow per share at a compound annual growth rate of approximately 29 percent. Cash flow has been driven largely by our growing production base with a low per unit cost structure and, until recently, strong commodity pricing. Commodity prices are always a risk.

To help safeguard our capital and dividend programs, we strive to create some certainty around the cash flow required to fund these programs. EnCana hedges commodity prices to manage volatility and typically hedges up to 50 percent of the upcoming year's production. EnCana has about two-thirds of our expected 2009 daily gas production hedged at an average price of \$9.13 per thousand cubic feet until the end of October. In cases where there are transportation constraints, EnCana will often hedge the basis differential, which reflects the cost of transportation between a production area and Henry Hub, North America's main pricing point for natural gas. Our hedging strategy helps to ensure that we have sufficient cash flow to fund our capital investment and free cash flow available to pay dividends. EnCana manages its financial exposure to hedging counterparties by transacting only with a select group of about 25 entities with high investment grade credit ratings.

Our hedging strategy helps to ensure that we have sufficient cash flow to fund our capital investment and free cash flow available to pay dividends.



IS ENCANA CONSIDERING LOWERING ITS DIVIDEND IN THIS ENVIRONMENT?

We consider dividends to be a fundamental part of our strategy to return value created to the company's owners. We believe our dividend to be an important component of EnCana's strategic positioning which distinguishes us amongst investment alternatives. The distribution of a significant dividend is reflective of the confidence we have in the long term free cash flow generation capacity of our assets and our business model. However, dividend payments are at the discretion of the Board of Directors. Given these extraordinary economic times, we will continue to assess our dividend on a quarterly basis.



GIVEN TIGHT DEBT MARKETS DOES ENCANA HAVE ANY DEBT MATURING IN THE NEAR FUTURE?

We have a modest amount of debt maturing over the next two years, \$250 million in August of 2009 and \$200 million in September of 2010. More than 80 percent of our outstanding debt is made up of long-term, fixed rate notes with maturities between 2009 and 2038. Approximately 73 percent of our outstanding debt is denominated in U.S. dollars. At the end of 2008, we had used less than 50 percent of our committed revolving credit facilities, leaving approximately \$2.6 billion undrawn and available.

Brian C. Ferguson
Executive Vice-President &
Chief Financial Officer



ENCANA SEES POSSIBILITIES BEFORE THEY BECOME OBVIOUS

We recognized several years ago that conventional production in North America was in steady decline, and that our future relied on our ability to unlock vast unconventional reservoirs on this continent, home to some of the largest known accumulations of natural gas and oil in the world. In 2004, we determined that North America would become the focus of our growth.

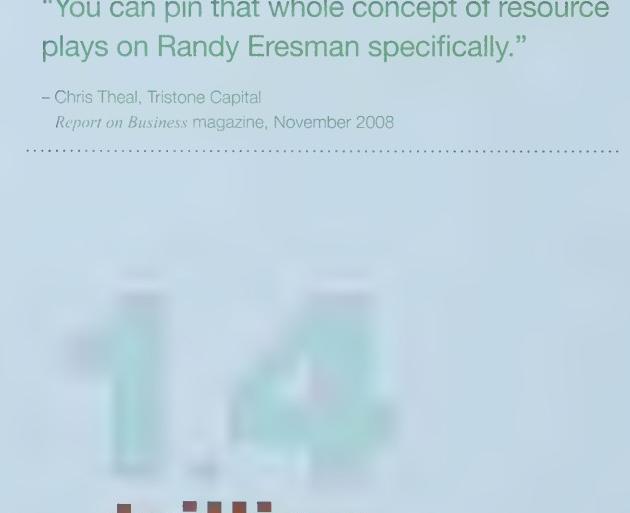
As others continued to expand globally, we were selling our international assets and examining the resource potential of every major basin on the continent. We increased our already extensive hydrocarbon-rich land base in North America, confident in our ability to advance the technology required to unlock the value.

Over the past five years, we have established ourselves as a leader in resource play development. Natural gas accounts for more than 80 percent of our total production. In 2008, we produced 1.4 trillion cubic feet of natural gas from approximately 47,000 wells across North America, enough to heat just under 11 million homes for one year.

The huge potential of unconventional reservoirs is now widely understood. Natural gas and oil resource plays are expected to be the most significant source of North American production growth for the industry.

"You can pin that whole concept of resource plays on Randy Eresman specifically."

– Chris Theal, Tristone Capital
Report on Business magazine, November 2008



trillion cubic feet

natural gas we produced in 2008 – enough to heat almost 11 million homes for one year.

 GREATER SIERRA
220 MMcf/d

 PELICAN LAKE
22 Mbbls/d

 CUTBANK RIDGE
296 MMcf/d

 CHRISTINA LAKE
4 Mbbls/d

 FOSTER CREEK
26 Mbbls/d

 BIGHORN
167 MMcf/d

 CBM
304 MMcf/d

 SHALLOW GAS
700 MMcf/d

 WEYBURN
14 Mbbls/d

 JONAH
603 MMcf/d

 PICEANCE
385 MMcf/d

WOOD RIVER  REFINERY

 BORGER
REFINERY

FORT WORTH 
142 MMcf/d

EAST TEXAS 
334 MMcf/d

OUR KEY RESOURCE PLAYS SPAN OUR VAST NORTH AMERICAN LAND HOLDINGS

EnCana coined the term “resource play.” The term is now widely used by industry to describe unconventional natural gas and oil development.

million net acres

EnCana's vast North American land position, which is about the size of 11.5 million Canadian football fields.

ENCANA KEY RESOURCE PLAYS
2008 AVERAGE DAILY PRODUCTION

 NATURAL GAS  OIL

OUR CULTURE IS ONE THAT UNLOCKS POTENTIAL – BOTH BELOW THE GROUND, AND FROM WITHIN OUR PEOPLE

seeing
THE
POSSIBILITIES

Our people are critical to our success. Since this industry is one of the most sophisticated and technology-intensive in the world, EnCana has built a high-performing workforce that excels in this environment.

Our people pursue innovation, bring leadership and passion to their work, and strengthen the teams they join. And they are accountable for developing objectives that guide them and the company to great results.

Over the years, we've learned that we can devise better ways of doing things when we share ideas. And by doing things better, we're able to decrease costs, increase production, create a safer work environment, and reduce our environmental footprint. We identify and apply the most effective technology to our resource plays to increase the amount of natural gas and oil we recover and drive down costs over time. Our teams continuously make small improvements that can be applied broadly and, in many cases, across all our operations.



Our innovative teams' ability to develop, test and implement technologies is key to unlocking the value from our resource plays.

acting
ON THE
POSSIBILITIES

NATURAL GAS

EVOLVING TECHNOLOGIES

As a result of sharing knowledge between our teams in North America we have implemented or, in many cases, evolved a number of technologies. In our natural gas operations, we've substantially reduced the number of drilling locations and the surface area of our operations by using horizontal well advancements to employ longer-reaching wells. This allows for an increased number of fracture stimulations (fracs) along the horizontal leg of the well, resulting in time and cost savings. Additionally, we've increased production from wells by changing the fracing fluid, and reduced flaring through the use of portable flowback test units. In 2007, we began using infrared cameras across our natural gas operations to detect leaks that are too small to be seen by the human eye or sensed by gas detection instrumentation. This has increased the safety of our operations and helped eliminate waste and inefficiency.

million

300+ automated rigs
powering 100% of our
powered rigs to natural gas.

INDUSTRY PARTNER

GAINING EXPOSURE TO FULL VALUE CHAIN

To expand our oil business, we determined we needed a more reliable market for our bitumen. The solution? An industry partner that could give us immediate participation in North American refining. The resulting 50/50 business venture with ConocoPhillips in 2007 paired two of our high-quality bitumen properties with two of their leading refineries. This gives us greater certainty to grow production from our SAGD projects by reducing price risk and gaining exposure to the full value chain – from the wellhead to transportation fuels – enhancing our ability to achieve strong economic returns. The first two years of this business venture have set the stage for a long-term mutually beneficial relationship.

The driller's control cabin pictured here is part of an automated rig built specifically for EnCana.



FIT-FOR-PURPOSE RIGS INCREASING SAFETY AND EFFICIENCY

Over the past two years, we have worked with drilling companies in North America to customize rigs to meet our specific and varied project needs with safety, environmental impact and efficiency as foremost priorities. To date, we have 60 fit-for-purpose rigs in use across our operations.

acting
ON THE
POSSIBILITIES



A drilling site at Christina Lake.

Foster Creek's gross production has grown steadily to approximately 60,000 barrels per day at the end of 2008.

SAGD TECHNOLOGY

LEADING THE WAY

Our development of oil properties in the Athabasca and Cold Lake regions in Alberta began in the mid-1990s with a pilot program, Foster Creek. A second pilot, Christina Lake, followed in 1997. Our experienced team has advanced the technology to better extract the abundant bitumen through the application of SAGD technology. We built and commissioned the world's first commercial SAGD project in 2001 at Foster Creek. With about 80 producing wells, Foster Creek's gross production has grown steadily to approximately 60,000 barrels per day at the end of 2008. The Christina Lake project is in an earlier stage of development with 15 wells, and had gross production of about 14,000 barrels per day at the end of 2008.

A key measure of efficiency for SAGD operations is the amount of steam needed to produce every barrel of bitumen. It's thanks to the quality of our assets and our team's dedication to continuously improve operational performance that our SAGD projects have achieved a steam to oil ratio of approximately 2.5, which is among the lowest in the industry. By using technologies such as electric submersible pumps, and solvent-aided processes (which combine a solvent, such as butane, with steam to help mobilize the bitumen), we continue to decrease the amount of steam required and thereby minimize emissions by reducing the amount of energy used.

WEYBURN OILFIELD

WORLD'S LARGEST CARBON CAPTURE PROJECT

Our enhanced oil recovery facility at the Weyburn field in Saskatchewan is the site of the largest CO₂ sequestration project in the world. This technology helps maximize the recovery of oil reserves while decreasing greenhouse gases released into the atmosphere. More than 13 million tonnes of CO₂ have been sequestered at Weyburn to date, with 30 million tonnes projected over the life of the field.

The cumulative reduction in greenhouse gas emissions at Weyburn is equal to taking about 6.7 million cars off the road for an entire year.

08 *execution* EXCELLENCE

During a year that saw extreme volatility in natural gas and oil prices and a challenging operating environment, our continued concentration on our resource play strategy delivered strong operational and financial performance. Once again, our operating focus in 2008 was on finding efficiencies and on excellence in execution in all facets of our business: from growing our resource base, to implementing new technologies, to sharing ideas, to introducing new employee programs. All the while we continued our commitment to working safely and being a trusted, thoughtful neighbour.

Highlights

SHALE PLAYS

AN EMERGING UNCONVENTIONAL NATURAL GAS RESOURCE

There was a lot of attention on shale gas as an emerging resource in 2008. Realizing the potential of this resource as early as 2003, we began acquiring the land and drilling rights to explore plays in the Haynesville Shale in Louisiana and Texas, and the Horn River Shale in British Columbia. Recent exploration wells drilled by EnCana, our partners and industry, indicate these natural gas reservoirs hold the potential to be among the largest sources of natural gas growth in North America. Each of these plays has been compared in size and scope to the prolific Barnett Shale in Texas, which currently produces about 4 billion cubic feet per day and continues to grow. We have assembled vast land positions in each of these emerging plays – 260,000 net acres in the heart of the Horn River Shale and 435,000 net acres, including 63,000 net acres of mineral rights, in the Haynesville Shale.

Shale plays have the potential to be among the largest sources of natural gas growth in North America.

CORE STRENGTH

EXPANDING UPSTREAM AND DOWNSTREAM TOGETHER

We began construction on a coker and refinery expansion (CORE) project at the Wood River Refinery, which will more than double its heavy oil refining capacity. The expansion will cost an estimated \$1.8 billion net to EnCana (\$3.6 billion gross) and is expected to be in full operation in 2011. Combined, the Wood River Refinery in Illinois and the Borger Refinery in Texas will have a total heavy oil refining capacity of about 275,000 barrels per day, placing us among the leading heavy oil refiners in the U.S. In parallel with the Wood River Refinery expansion, the integrated oil venture between EnCana and ConocoPhillips has approved upstream expansions at Foster Creek and Christina Lake in northern Alberta, where we expect gross bitumen production capacity will grow from the current level of 78,000 barrels per day to about 178,000 barrels per day in 2011.

EnCana expects more than just hard work from its employees and contractors. It's a company that expects them to be innovative and make the most of their ideas.

TIME SAVER

ADVANCES IN HORIZONTAL WELL COMPLETIONS



demonstrated reduction in deep natural gas frac time.

In 2008, we implemented the use of long-reach horizontal wells and multi-stage hydraulic fracturing technology more broadly across our natural gas resource plays, including the Montney and Horn River plays in British Columbia and the Haynesville play in Louisiana and Texas. This approach has resulted in improved economics and reduced environmental footprint for our plays. The horizontal leg of each well can extend as far as two kilometres in length and support as many as 14 frac stages. Using this multi-stage completions approach has multiple benefits. It decreases the number of wells that we have to drill to access the resource, minimizes the number of days it takes to fracture a well – from as many as 30 down to as few as two or three in some cases – and enables us to centralize our gathering and processing facilities allowing manufacturing-type operations to be conducted. Together, these improvements can reduce our overall surface footprint, and generate significant cost savings.

GETTING THE LAST DROP

WEDGE WELLS

We developed and proved the concept of wedge wells, a new approach that enables us to extract more bitumen from our SAGD operations. During the SAGD process, a considerable amount of heated bitumen sits undrained between adjacent steam chambers. Using wedge wells, single horizontal wells drilled between two SAGD well pairs, we can now extract much of the bitumen that was previously unrecovered. Since wedge wells require minimal steam to extract the remaining bitumen, we have been able to increase our bitumen production by about 500 barrels per day per wedge well while at the same time reducing our per barrel operating costs, water use and environmental impact. A patent on this technology is pending.

“EnCana’s wedge well innovation will radically alter perceptions on SAGD economics and recovery factor limitations.”

– TD Newcrest, January 2009

WASTE NOT

ENHANCED WATER RECYCLING

We developed an enhanced steam generation process that significantly improves water recycling. After a boiler converts most of its water into steam, about one-quarter of the water is left over. To minimize waste, we developed a process to re-boil this blowdown water in a second boiler to make more steam. This energy efficient process helps increase our water recycling rate to more than 90 percent at Foster Creek – a significant milestone in the evolution of our SAGD technology. We have tested the process extensively in the field and have filed for a patent.

08 execution EXCELLENCE

SHARING KNOWLEDGE

GENERATING NEW IDEAS

More than 2,500 EnCana staff from all our disciplines across North America gathered in Calgary in May 2008 for our third biennial gEnerate Summit. The goal of the Summit is to impart learnings and enhance our execution excellence by sharing information on new technologies and innovations, and learning from our challenges and successes. Consisting of poster sessions, panel discussions, and feature presentations, the Summit is our largest staff networking and knowledge-sharing opportunity.

INVESTING IN FUTURE SOLUTIONS

ENVIRONMENTAL INNOVATION FUND

Last year, through our Environmental Innovation Fund, we entered into an agreement to contribute C\$3 million over a three-year period to a technology that gives end users the potential to reduce emissions and improve their efficiency. Atlantic Hydrogen's CarbonSaver™ Demonstration Project captures carbon as a solid – which has the potential to be sold for use in products such as tires, inks, and plastics – while the extraction process leaves behind a hydrogen-enriched natural gas low-emissions fuel. An industry first of its kind, our Environmental Innovation Fund invests in people and ideas that address future solutions. It focuses on advancing technologies that aim to reduce emissions, increase energy efficiency, improve water conservation, enhance waste management, and develop new renewable energy. We continuously review opportunities to support new clean-energy technologies.



million

committed to 17 projects to date in North America.

COURTESY MATTERS

PUTTING COMMUNITY NEEDS FIRST

Our Courtesy Matters™ program, which we originally created in 2006 to address community concerns in our operating areas, is attracting attention from other companies in the industry. In 2008 the Petroleum Services Association of Canada endorsed the merits of our program with its member companies. Courtesy Matters™ addresses nuisance issues sometimes associated with the oil and gas industry, such as noise, dust, garbage, and increased traffic. The program focuses on putting the needs of the community first and doing what we can to ensure a long-lasting mutual respect.

“PSAC members have been pleased to work with EnCana on the Courtesy Matters™ program because it provides innovative solutions to issues in communities where we work and makes a genuine difference.”

– Rob Gray, Manager, Communications & Member Relations
Petroleum Services Association of Canada (PSAC)

08 *execution* EXCELLENCE

SAM AWARD

INTERNATIONAL RECOGNITION

In addition to three straight years on the Dow Jones Sustainability Index, we have also been awarded a Sustainable Asset Management (SAM) distinction for demonstrating leadership in sustainability for the second year in a row. We are the only North American company to be recognized with a class distinction for our 2008 operations under the category of 'Oil & Gas Producers' in the Sustainability Yearbook 2009.



million

invested in 2008 in community programs – from sports, recreation and wellness, to education, science and technology.

MORE CASH FOR NON-PROFIT ORGANIZATIONS

EMPLOYEES GIVING TIME

In recognition of their time volunteered, we introduced a program in 2008 that supports all our employees and their families in making a difference in their communities. What's different about our program is that it gives employees and their immediate families the opportunity to volunteer together and apply for a donation from EnCana to the non-profit organizations where they give their time. The donation is based on the total volunteer hours of each family member. In 2008, we received the Generosity of Spirit Award from the Association of Fundraising Professionals. Nominated by Imagine Canada, we were identified as a company that plays a significant role in improving Canadian communities through financial support and donations in-kind, as well as for encouraging employee volunteerism and matching employee donations dollar for dollar.

million

given by employees across North America to non-profit organizations of their choice. The company match increased that total to more than C\$6.2 million.



CHAIRMAN'S MESSAGE

EnCana delivered strong performance in 2008 as management and the Board of Directors applied a steady hand and sharp focus on capital discipline, risk management and sound corporate governance during a year of considerable economic and commodity price volatility. The Board's combined decades of experience enabled us to provide knowledgeable advice and support to EnCana's executives as they worked to ensure the company's continued success despite the market challenges.

As with every strategic decision the company makes, shareholders' interests were top of mind when the Board approved the decision in May to split EnCana into two publicly traded companies, and then endorsed the move in October to delay those plans. When there are clear signs of stabilization in the global financial markets, the executives and the Board will reassess those plans as part of the company's continued pursuit of strategies that enhance shareholder value.

A significant role of the Board is to ensure that a system is in place to identify the principal risks to EnCana, including those risks inherent to the energy industry, and that the best practical procedures are in place to monitor and mitigate the risks. Board members are responsible for approving EnCana's Corporate Risk Management Policy and monitoring compliance. EnCana's Chief Risk Officer, an executive-level position created in 2007, provides regular updates to the Board about the identification and mitigation of principal risks in all areas of the company, including those of a financial, operational, safety, environmental and regulatory nature, and whether they have strategic or near-term impacts. Board members are supportive of EnCana's efforts to continually improve its risk management strategy and procedures.

The strength of EnCana's corporate governance was even more evident in 2008 as the Board provided oversight for strategic actions taken during a time of extreme market turbulence. In addition, EnCana continues to fully comply with the applicable corporate governance requirements, including best practices guidelines published by the Canadian securities regulatory authorities, the provisions of the Sarbanes-Oxley Act of 2002 and the rules adopted by the U.S. Securities and Exchange Commission pursuant to that Act. The company is also in compliance with all applicable New York Stock Exchange requirements and is committed to high standards of transparent reporting and accountability.

I was pleased to welcome Claire Farley to the Board in April 2008. Ms. Farley contributes a wealth of knowledge and experience in all aspects of the oil and gas business. I want to express my appreciation to retiring Board members Dale Lucas and Jim Stanford for their contributions to EnCana's Board over many years. We wish them well in their future endeavours.

It has been a privilege for me to serve another year as EnCana's Chairman and I want to thank all Board members for their dedication and leadership throughout 2008. I also want to offer special thanks to EnCana's executive team and all employees and contractors. They put in an extraordinary effort this year as they dealt with the challenges presented by the dynamic business environment. EnCana has a strong financial and asset base which will enable us to successfully navigate the challenging times in 2009.

On behalf of the Board of Directors,

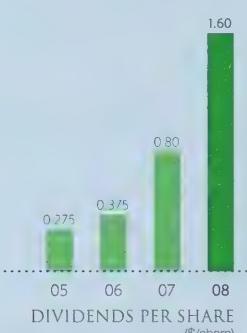
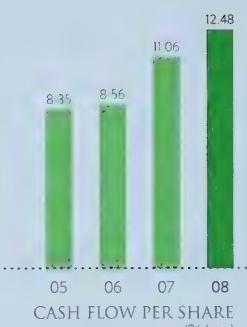


David P. O'Brien
Chairman of the Board



FINANCIAL HIGHLIGHTS

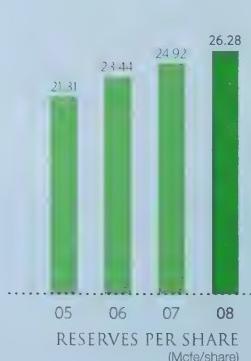
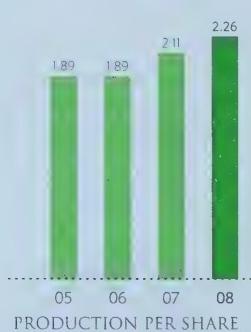
US\$ millions, except per share amounts	2008	2007	% Change
Revenues, Net of Royalties	30,064	21,700	39
Cash Flow ⁽¹⁾	9,386	8,453	11
Per Share – Diluted	12.48	11.06	13
Net Earnings	5,944	3,959	50
Per Share – Diluted	7.91	5.18	53
Operating Earnings ⁽¹⁾	4,405	4,100	7
Per Share – Diluted	5.86	5.36	9
Total Capital Investment	7,080	6,035	17
Net Acquisition & Divestiture Activity	270	2,221	(88)
Net Capital Investment	7,350	8,256	(11)
Dividends Per Common Share (\$/share)	1.60	0.80	100
Dividend Yield (%) ⁽²⁾	3.4	1.2	183
Debt to Capitalization (%) ⁽¹⁾	28	32	(13)
Debt to EBITDA (times) ⁽¹⁾	0.7	1.1	(36)
Debt ⁽¹⁾ to Proved Developed Reserves (\$/Mcfe)	0.83	0.94	(12)



(1) Non-GAAP measures as referenced in the Advisory on page 70.
(2) Based on NYSE closing share price at year end.

OPERATING HIGHLIGHTS

After royalties	2008	2007	% Change
Production			
Natural Gas (MMcf/d)			
Canada	2,205	2,221	(1)
USA	1,633	1,345	21
Total Natural Gas (MMcf/d)	3,838	3,566	8
Oil & NGLs (bbls/d)			
Foster Creek & Christina Lake	30,183	26,814	13
North America, Other	103,397	107,340	(4)
Total Oil & NGLs (bbls/d)	133,580	134,154	–
Total Production (MMcf/d)	4,639	4,371	6
Refinery Operations⁽¹⁾			
Crude Oil Capacity (Mbbls/d)	452	452	–
Crude Oil Runs (Mbbls/d)	423	432	(2)
Reserves⁽²⁾			
Year-End Reserves (Bcfe)	19,712	18,863	
Net Reserve Additions (Bcfe) ⁽³⁾	2,547	3,629	
Production Replacement (%)	150	227	
Finding & Development Cost (\$/Mcfe)	2.50	1.65	
Recycle Ratio	2.6	3.5	
Reserve Life Index (years)	11.6	11.8	



(1) Represents 100% of the Wood River and Borger refinery operations.
(2) Proved reserves only.
(3) 2007 excludes Foster Creek and Christina Lake reserves contributed to a 50/50 upstream partnership with ConocoPhillips.

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MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") for EnCana Corporation ("EnCana" or the "Company") should be read with the audited Consolidated Financial Statements for the year ended December 31, 2008, as well as the audited Consolidated Financial Statements and MD&A for the year ended December 31, 2007. Readers should also read the "Forward-Looking Statements" legal advisory contained at the end of this document.

The Consolidated Financial Statements and comparative information have been prepared in United States ("U.S.") dollars, except where another currency has been indicated, and in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"). Production volumes are presented on an after royalties basis consistent with U.S. protocol reporting. This document is dated effective February 19, 2009.

Readers can find the definition of certain terms used in this document in the disclosure regarding Oil and Gas Information and Currency, Non-GAAP Measures and References to EnCana contained in the Advisories section located at the end of this document.

EnCana's Financial Strategy in the Current Economic Environment

The current economic environment is challenging and uncertain amidst a global recession, low commodity prices, volatile financial markets and limited access to capital markets.

In this environment, EnCana is highly focused on the key business objectives of maintaining financial strength, generating significant free cash flow, further optimizing capital investments and continuing to pay a stable dividend to shareholders. This measured investment approach is underpinned by a strong balance sheet and a market risk mitigation strategy where EnCana has hedged about two thirds of its expected gas production from January through October 2009 at an average NYMEX equivalent price of about \$9.13 per Mcf, along with other actions within its risk management program that are more fully described in the Risk Management section of this MD&A.

EnCana has a strong balance sheet and continues to employ a conservative capital structure. As at December 31, 2008, over 80 percent of EnCana's outstanding debt was composed of long-term, fixed rate debt with an average remaining term of more than 14 years. Long-term maturities are \$250 million in 2009 and \$200 million in 2010. As at December 31, 2008, EnCana had available unused capacity under shelf prospectuses, the availability of which is dependent on market conditions, for up to \$5.0 billion and unused committed bank credit facilities in the amount of \$2.6 billion. EnCana targets a Debt to Capitalization ratio of between 30 to 40 percent and, at December 31, 2008, the Company's Debt to Capitalization ratio was 28 percent.

In addition, EnCana will continue to monitor expenses and capital programs. In light of the current market situation, EnCana has planned a measured, flexible approach to 2009 investment and has designed a 2009 capital program with the flexibility to adjust investment up or down depending upon how economic circumstances unfold during the year. Additional detail regarding EnCana's 2009 capital investment is available in the Corporate Guidance on the Company's website at www.encana.com.

EnCana's Business

EnCana is a leading North American unconventional natural gas and integrated oil company.

On May 11, 2008, EnCana announced its plans to split into two independent energy companies – one a North American natural gas company and the other a fully integrated oil company with in-situ oil properties and refineries supplemented by reliable production from various natural gas and crude oil resource plays.

The proposed corporate reorganization (the "Arrangement") would be implemented through a court approved Plan of Arrangement and is subject to shareholder approval. The Arrangement would result in two publicly traded entities with the names of Cenovus Energy Inc. ("Cenovus") and EnCana Corporation. Each EnCana shareholder would receive one share of each entity in exchange for each EnCana Common Share held.

On October 15, 2008, EnCana announced the proposed Arrangement would be delayed until the global debt and equity markets regain stability. Meanwhile, the Company remains focused on being a leading producer of unconventional natural gas and in-situ oil as well as participating in the downstream refining and marketing of petroleum products. Additional details on the Arrangement are available in the 2008 news releases dated May 11, October 15, October 23 and December 11 on the Company's website at www.encana.com.

EnCana's operating divisions, post-Arrangement, would include Canadian Foothills and USA. Cenovus' operating divisions, post-Arrangement, would include Canadian Plains and Integrated Oil.

EnCana's operating and reportable segments are as follows:

- **Canada** includes the Company's exploration for, and development and production of natural gas, crude oil and natural gas liquids ("NGLs") and other related activities within the Canadian cost centre.
- **USA** includes the Company's exploration for, and development and production of natural gas, NGLs and other related activities within the United States cost centre.
- **Downstream Refining** is focused on the refining of crude oil into petroleum and chemical products at two refineries located in the United States. The refineries are jointly owned with ConocoPhillips.
- **Market Optimization** is primarily responsible for the sale of the Company's proprietary production. These results are included in the Canada and USA segments. Market optimization activities include third-party purchases and sales of product that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification. These activities are reflected in the Market Optimization segment.
- **Corporate and Other** mainly includes unrealized gains or losses recorded on derivative financial instruments. Once amounts are settled, the realized gains and losses are recorded in the operating segment to which the derivative instrument relates.

Market Optimization markets substantially all of the Company's upstream production to third-party customers. Transactions between segments are based on market values and eliminated on consolidation. Segmented financial information is presented on an after eliminations basis.

EnCana has updated its segmented reporting to present the upstream Canadian and United States cost centres and Downstream Refining as separate reportable segments. This results in EnCana presenting the Canadian portion of the Integrated Oil Division as part of the Canada segment. Previously, this was aggregated and presented in the Integrated Oil segment. Prior periods have been restated to reflect the new presentation.

EnCana has a decentralized decision making and reporting structure. Accordingly, the Company is organized into divisions as follows:

- **Canadian Plains** Division includes natural gas production and crude oil development and production assets located in eastern Alberta and Saskatchewan.
- **Canadian Foothills** Division includes natural gas development and production assets located in western Alberta and British Columbia as well as the Company's Canadian offshore assets.
- **USA** Division includes the assets located in the United States and comprises the USA segment described above.
- **Integrated Oil** Division is the combined total of Integrated Oil – Canada and Downstream Refining. Integrated Oil – Canada includes the Company's exploration for, and development and production of bitumen using in-situ recovery methods. Integrated Oil – Canada is composed of EnCana's interests in the FCCL Oil Sands Partnership jointly owned with ConocoPhillips, the Athabasca natural gas assets and other bitumen interests.

2008 Overview

In 2008 compared to 2007, EnCana:

- Increased Cash Flow by 11 percent to \$9,386 million;
- Increased Operating Earnings by 7 percent to \$4,405 million;
- Reported a 50 percent increase in Net Earnings to \$5,944 million primarily due to after-tax unrealized mark-to-market hedging gains of \$1,818 million in 2008 compared to losses of \$811 million in 2007;
- Reported Free Cash Flow of \$2,306 million which is slightly lower compared to 2007;

- Grew total production 6 percent to 4,639 million cubic feet equivalent ("MMcfe") per day ("MMcfe/d"). On a per share basis, production increased 7 percent;
- Increased production from natural gas key resource plays 14 percent and from oil key resource plays 2 percent;
- Reported a 35 percent increase in natural gas prices, excluding financial hedges, to \$7.94 per thousand cubic feet ("Mcf") and a 53 percent increase in liquids prices, excluding financial hedges, to \$76.58 per barrel ("bbl"). Realized hedging losses were \$219 million after-tax in 2008 compared to gains of \$1,023 million after-tax in 2007;
- Reported a \$1,315 million decrease in operating cash flows from downstream operations;
- Acquired additional land acreage in the Haynesville Shale play in Louisiana for approximately \$1,010 million;
- Completed the sale of mature conventional oil and natural gas assets in North America for proceeds of \$698 million and interests in Brazil for proceeds of \$164 million before closing adjustments;
- Purchased approximately 4.8 million of its Common Shares at an average price of \$67.13 per share under the Normal Course Issuer Bid ("NCIB") for a total cost of \$326 million in 2008 compared to approximately 38.9 million of its Common Shares at an average price of \$52.05 per share for a total cost of \$2,025 million in 2007;
- Added net proved natural gas reserves of 1,783 billion cubic feet ("Bcf") and crude oil and NGLs reserves of 127 million barrels ("MMbbls");
- Increased its quarterly dividends to 40 cents per share in 2008 compared to 20 cents per share in 2007; and
- Reported a Debt to Adjusted Earnings Before Interest, Taxes, Depreciation and Amortization ("EBITDA") of 0.7x and a Debt to Capitalization ratio of 28 percent at December 31, 2008.

Business Environment

EnCana's financial results are significantly influenced by fluctuations in commodity prices, which include price differentials, crack spreads and the U.S./Canadian dollar exchange rate. The following table shows select market benchmark prices and foreign exchange rates to assist in understanding EnCana's financial results:

(Average for the year ended December 31)	2008	2008 vs 2007		2007	2007 vs 2006		2006
		2008	2007		2007	2006	
Natural Gas Price Benchmarks							
AECO (C\$/Mcf)	\$ 8.13	23%	\$ 6.61	-5%	\$ 6.98		
NYMEX (\$/MMBtu)	9.04	32%	6.86	-5%	7.22		
Rockies (Opal) (\$/MMBtu)	6.25	58%	3.95	-30%	5.65		
Texas (HSC) (\$/MMBtu)	8.67	32%	6.58	1%	6.53		
Basis Differential (\$/MMBtu)							
AECO/NYMEX	1.23	64%	0.75	-29%	1.06		
Rockies/NYMEX	2.79	-4%	2.91	85%	1.57		
Texas/NYMEX	0.37	32%	0.28	-60%	0.70		
Crude Oil Price Benchmarks							
West Texas Intermediate (WTI) (\$/bbl)	99.75	38%	72.41	9%	66.25		
Western Canadian Select (WCS) (\$/bbl)	79.70	61%	49.50	11%	44.69		
Differential – WTI/WCS (\$/bbl)	20.05	-12%	22.91	6%	21.56		
Refining Margin Benchmark							
Chicago 3-2-1 Crack Spread (\$/bbl) ⁽¹⁾	11.22	-37%	17.67	32%	13.38		
Foreign Exchange							
U.S./Canadian Dollar Exchange Rate	0.938	1%	0.930	5%	0.882		

(1) 3-2-1 Crack Spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of gasoline and one barrel of diesel. 2006 value is calculated using Low Sulphur Diesel; 2007 and 2008 values are calculated using Ultra Low Sulphur Diesel.

The following table shows benchmark information on a quarterly basis to assist in understanding quarterly volatility in prices and foreign exchange rates that have impacted EnCana's financial results:

Quarterly Market Benchmark Prices and Foreign Exchange Rates

(Average for the period)	2008	Q4	Q3	Q2	Q1	2007	Q4	Q3	Q2	Q1
Natural Gas Price Benchmarks										
AECO (C\$/Mcft)	\$ 8.13	\$ 6.79	\$ 9.24	\$ 9.35	\$ 7.13	\$ 6.61	\$ 6.00	\$ 5.61	\$ 7.37	\$ 7.46
NYMEX (\$/MMBtu)	9.04	6.94	10.24	10.93	8.03	6.86	6.97	6.16	7.55	6.77
Rockies (Opal) (\$/MMBtu)	6.25	3.53	5.88	8.56	7.02	3.95	3.46	2.94	3.85	5.54
Texas (HSC) (\$/MMBtu)	8.67	6.37	9.98	10.58	7.73	6.58	6.64	5.89	7.26	6.54
Basis Differential (\$/MMBtu)										
AECO/NYMEX	1.23	1.10	1.28	1.71	0.84	0.75	0.85	0.84	0.90	0.40
Rockies/NYMEX	2.79	3.41	4.36	2.37	1.01	2.91	3.50	3.22	3.70	1.23
Texas/NYMEX	0.37	0.58	0.26	0.35	0.30	0.28	0.33	0.27	0.29	0.23
Crude Oil Price Benchmarks										
WTI (\$/bbl)	99.75	59.08	118.22	123.80	97.82	72.41	90.50	75.15	65.02	58.23
WCS (\$/bbl)	79.70	39.95	100.22	102.18	76.37	49.50	56.85	52.71	45.84	41.77
Differential – WTI/WCS (\$/bbl)	20.05	19.13	18.00	21.62	21.45	22.91	33.65	22.44	19.18	16.46
Refining Margin Benchmark										
Chicago 3-2-1 Crack Spread (\$/bbl) ⁽¹⁾	11.22	6.31	17.29	13.60	7.69	17.67	9.17	18.48	30.12	12.90
Foreign Exchange										
U.S./Canadian Dollar Exchange Rate	0.938	0.825	0.961	0.990	0.996	0.930	1.019	0.957	0.911	0.854

(1) 3-2-1 Crack Spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of gasoline and one barrel of diesel. 2007 and 2008 values are calculated using Ultra Low Sulphur Diesel.

Consolidated Financial Results

(\$ millions, except per share amounts)	2008	Q4	Q3	Q2	Q1	2007	Q4	Q3	Q2	Q1	2006
Total Consolidated											
Cash Flow ⁽¹⁾	\$ 9,386	\$ 1,299	\$ 2,809	\$ 2,889	\$ 2,389	\$ 8,453	\$ 1,934	\$ 2,218	\$ 2,549	\$ 1,752	\$ 7,161
per share – diluted	12.48	1.73	3.74	3.85	3.17	11.06	2.56	2.93	3.33	2.25	8.56
Net Earnings	5,944	1,077	3,553	1,221	93	3,959	1,082	934	1,446	497	5,652
per share – basic	7.92	1.44	4.74	1.63	0.12	5.23	1.44	1.24	1.91	0.65	6.89
per share – diluted	7.91	1.43	4.73	1.63	0.12	5.18	1.43	1.24	1.89	0.64	6.76
Operating Earnings ⁽²⁾	4,405	449	1,442	1,469	1,045	4,100	849	1,032	1,369	850	3,271
per share – diluted	5.86	0.60	1.92	1.96	1.39	5.36	1.12	1.37	1.79	1.09	3.91
Total Assets	47,247					46,974					35,106
Total Long-Term Debt	9,005					9,543					6,834
Cash Dividends – per share	1.60	0.40	0.40	0.40	0.40	0.80	0.20	0.20	0.20	0.20	0.375
Revenues, Net of Royalties	30,064	6,359	10,849	7,422	5,434	21,700	5,875	5,654	5,674	4,497	16,670

(1) Cash Flow is a non-GAAP measure and is defined under the Cash Flow section of this MD&A.

(2) Operating Earnings is a non-GAAP measure and is defined under the Operating Earnings section of this MD&A.

CASH FLOW

Cash Flow is a non-GAAP measure defined as cash from operating activities excluding net change in other assets and liabilities, net change in non-cash working capital from continuing operations and net change in non-cash working capital from discontinued operations. Cash Flow from Continuing Operations is a non-GAAP measure defined as cash flow excluding cash flow from discontinued operations. While cash flow measures are considered non-GAAP, they are commonly used in the oil and gas industry and by EnCana to assist Management and investors in measuring the Company's ability to finance capital programs and meet financial obligations.

Summary of Cash Flow

(\$ millions)	2008	2007	2006
Cash From Operating Activities	\$ 8,855	\$ 8,429	\$ 7,973
(Add back) deduct:			
Net change in other assets and liabilities	(262)	(16)	138
Net change in non-cash working capital	(269)	(8)	3,343
Net change in non-cash working capital from Discontinued Operations	-	-	(2,669)
Cash Flow	\$ 9,386	\$ 8,453	\$ 7,161

2008 Versus 2007

Cash Flow in 2008 increased \$933 million or 11 percent compared to 2007 as a result of:

- Average total natural gas prices, excluding financial hedges, increased 35 percent to \$7.94 per Mcf in 2008 compared to \$5.89 per Mcf in 2007;
- Average total liquids prices, excluding financial hedges, increased 53 percent to \$76.58 per bbl in 2008 compared to \$50.05 per bbl in 2007;
- Natural gas production volumes in 2008 increased 8 percent to 3,838 million cubic feet ("MMcf") per day ("MMcf/d") from 3,566 MMcf/d in 2007; and
- In addition to the reduction in current tax associated with realized financial hedging mentioned below, current income tax decreased primarily as a result of accelerated write-offs for certain U.S. capital expenditures and increased benefits from international financing partially offset by a one time tax recovery of \$179 million in 2007 for a Canadian tax legislative change.

Cash Flow was reduced by:

- Operating cash flows from downstream operations decreased \$1,315 million primarily due to weaker refining margins and higher purchased product costs;
- Realized financial natural gas, crude oil and other commodity hedging losses of \$219 million after-tax in 2008 compared to gains of \$1,023 million after-tax in 2007; and
- Increases in transportation and selling, operating, production and mineral taxes, interest and administrative expenses in 2008 compared to 2007.

2007 Versus 2006

EnCana's 2007 Cash Flow of \$8,453 million increased \$1,292 million or 18 percent compared to 2006 Cash Flow of \$7,161 million.

Cash Flow from Continuing Operations in 2007 was \$8,453 million (2006 – \$7,043 million). The decrease in Cash Flow from Discontinued Operations of \$118 million was primarily due to the sales of the gas storage business and Ecuador assets in 2006 (discussed in the Discontinued Operations section of this MD&A).

The increase in Cash Flow from Continuing Operations in 2007 compared to 2006 resulted from:

- Realized financial natural gas, crude oil and other commodity hedging gains were \$1,023 million after-tax in 2007 compared to gains of \$263 million after-tax in 2006;
- Operating cash flows from downstream operations was \$1,074 million in 2007 with no comparative amount in 2006;
- Natural gas production volumes in 2007 increased 6 percent to 3,566 MMcf/d from 3,367 MMcf/d in 2006; and
- Average North American liquids prices, excluding financial hedges, increased 15 percent to \$50.05 per bbl in 2007 compared to \$43.71 per bbl in 2006.

Cash Flow from Continuing Operations was reduced by:

- Cash taxes were \$1,554 million in 2007 compared to \$942 million in 2006 primarily as a result of increased operating cash flows in the U.S. and higher realized financial hedging gains offset partially by a \$179 million recovery due to a Canadian federal corporate tax legislative change;
- Average North American natural gas prices, excluding financial hedges, decreased 6 percent to \$5.89 per Mcf in 2007 compared to \$6.25 per Mcf in 2006; and
- North American liquids production volumes decreased 15 percent to 134,154 barrels per day ("bbls/d") in 2007 from 157,273 bbls/d in 2006. This decrease reflects the increased production volumes at Foster Creek offset by EnCana's 50 percent contribution of the Foster Creek and Christina Lake properties to the joint venture with ConocoPhillips and natural declines in conventional properties.

Q4 2008 Versus Q4 2007

Cash Flow in 2008 decreased \$635 million or 33 percent compared to 2007 as a result of:

- Operating cash flows from downstream operations decreased \$760 million primarily due to weaker refining margins and higher purchased product costs;
- Average total liquids prices, excluding financial hedges, decreased 43 percent to \$33.81 per bbl in 2008 compared to \$59.60 per bbl in 2007; and
- Average total natural gas prices, excluding financial hedges, decreased 7 percent to \$5.44 per Mcf in 2008 compared to \$5.83 per Mcf in 2007.

Cash Flow was increased by:

- Current income tax decreased primarily as a result of decreased cash flow in the quarter as well as accelerated write-offs for certain U.S. capital expenditures and increased benefits from international financing partially offset by the tax increase associated with realized financial hedging mentioned below;
- Realized financial natural gas, crude oil and other commodity hedging gains of \$439 million after-tax in 2008 compared to gains of \$246 million after-tax in 2007; and
- Natural gas production volumes in 2008 increased 4 percent to 3,858 MMcf/d from 3,722 MMcf/d in 2007.

NET EARNINGS

2008 Versus 2007

EnCana's 2008 Net Earnings of \$5,944 million were \$1,985 million higher compared to 2007. Net Earnings are equal to Net Earnings from Continuing Operations in 2008. Net Earnings from Discontinued Operations of \$75 million in 2007 were related to final adjustments on the December 2005 sale of the Company's Midstream NGLs processing operations.

EnCana's 2008 Net Earnings from Continuing Operations were \$2,060 million higher compared to 2007. In addition to the items affecting Cash Flow from Continuing Operations as detailed previously, significant items affecting Net Earnings from Continuing Operations were:

- Unrealized mark-to-market hedging gains of \$1,818 million after-tax in 2008 compared to losses of \$811 million after-tax in 2007;
- A gain of \$99 million after-tax from the sale of interests in Brazil in 2008 compared to gains of \$59 million and \$25 million after-tax from the sale of interests in Chad and assets in Australia, respectively, in 2007;
- Depreciation, depletion and amortization ("DD&A") increased \$407 million in 2008 compared to 2007 primarily due to the increase in production volumes;
- Non-operating foreign exchange losses of \$378 million after-tax in 2008 compared to gains of \$217 million after-tax in 2007; and
- Future income tax increased primarily as a result of the unrealized mark-to-market hedging gains mentioned above, accelerated write-offs for certain U.S. capital expenditures and the effect of the reduction in Canadian federal corporate tax rates reflected in 2007 offset partially by a tax recovery on non-operating foreign exchange losses mentioned above.

2007 Versus 2006

EnCana's 2007 Net Earnings were \$3,959 million, a decrease of \$1,693 million compared to 2006. Net Earnings from Discontinued Operations of \$75 million in 2007 decreased \$526 million from 2006 primarily due to sales of the gas storage business and Ecuador assets in 2006 (discussed in the Discontinued Operations section of this MD&A).

EnCana's 2007 Net Earnings from Continuing Operations were \$3,884 million or \$1,167 million lower than 2006. In addition to the items affecting Cash Flow from Continuing Operations as detailed previously, significant items affecting Net Earnings from Continuing Operations were:

- Unrealized mark-to-market losses of \$811 million after-tax in 2007 compared to gains of \$1,357 million after-tax in 2006;
- DD&A increased \$704 million in 2007 compared to 2006 primarily due to higher future development costs, the higher U.S./Canadian dollar exchange rate and the increase in production volumes. In addition, downstream refining DD&A was \$159 million in 2007 with no comparative amount in 2006;
- A gain on sale of approximately \$255 million after-tax from the sale of a 50 percent interest in the Chinook heavy oil discovery offshore Brazil in 2006;
- Reductions in future income tax in addition to the impact detailed above related to the unrealized mark-to-market losses; and
- Non-operating foreign exchange gains of \$217 million after-tax in 2007 with no comparative amount in 2006.

Q4 2008 Versus Q4 2007

EnCana's 2008 Net Earnings of \$1,077 million were \$5 million lower compared to 2007. In addition to the items affecting Cash Flow as detailed previously, significant items affecting Net Earnings were:

- Non-operating foreign exchange losses of \$119 million after-tax in 2008 compared to gains of \$267 million after-tax in 2007;
- Future income tax increased primarily as a result of the unrealized mark-to-market hedging gains mentioned above, accelerated write-offs for certain U.S. capital expenditures and the effect of the reduction in Canadian federal corporate tax rates reflected in the fourth quarter of 2007 offset partially by a tax recovery on non-operating foreign exchange losses mentioned below;
- DD&A decreased \$90 million in 2008 compared to 2007 primarily due to the lower U.S./Canadian dollar exchange rate and lower international impairments offset partially by the increase in production volumes; and
- Unrealized mark-to-market hedging gains of \$747 million after-tax in 2008 compared to losses of \$366 million after-tax in 2007.

OPERATING EARNINGS

Operating Earnings is a non-GAAP measure that adjusts Net Earnings by non-operating items that Management believes reduces the comparability of the Company's underlying financial performance between periods. The following reconciliation of Operating Earnings has been prepared to provide investors with information that is more comparable between periods.

Summary of Operating Earnings

(\$ millions, except per share amounts)	2008		2007		2006	
	Per share ⁽⁵⁾		Per share ⁽⁶⁾		Per share ⁽⁵⁾	
Net Earnings, as reported	\$ 5,944	\$ 7.91	\$ 3,959	\$ 5.18	\$ 5,652	\$ 6.76
Add back (losses) and deduct gains:						
Unrealized mark-to-market accounting gain (loss), after-tax	1,818	2.42	(811)	(1.06)	1,370	1.64
Non-operating foreign exchange gain (loss), after-tax ⁽¹⁾	(378)	(0.50)	217	0.28	—	—
Gain (loss) on discontinuance, after-tax ⁽²⁾	99	0.13	152	0.20	554	0.66
Future tax recovery due to tax rate reductions	—	—	301	0.40	457	0.55
Operating Earnings ⁽³⁾⁽⁴⁾	\$ 4,405	\$ 5.86	\$ 4,100	\$ 5.36	\$ 3,271	\$ 3.91

- (1) Unrealized foreign exchange gain (loss) on translation of Canadian issued U.S. dollar debt, the partnership contribution receivable, realized foreign exchange gain (loss) on settlement of intercompany transactions, after-tax and future income tax on foreign exchange related to U.S. dollar intercompany debt recognized for tax purposes only. The majority of U.S. dollar debt issued from Canada has maturity dates in excess of five years.
- (2) For 2008, gain on sale of interests in Brazil. For 2007, gain on sale of Australia assets and interests in Chad as well as final adjustments on the NGL processing business sold in 2005. For 2006, gain on sale of storage facilities and interests in Ecuador.
- (3) Operating Earnings is a non-GAAP measure defined as Net Earnings excluding the after-tax gain/loss on discontinuance, after-tax effect of unrealized mark-to-market accounting gains/losses on derivative instruments, after-tax gains/losses on translation of U.S. dollar denominated debt issued from Canada and the partnership contribution receivable, after-tax foreign exchange gains/losses on settlement of intercompany transactions, future income tax on foreign exchange related to U.S. dollar intercompany debt recognized for tax purposes only and the effect of changes in statutory income tax rates. In 2007, EnCana changed its calculation of Operating Earnings to exclude the foreign exchange effects on settlement of significant intercompany transactions to provide information that is more comparable between periods.
- (4) Unrealized gains or losses and realized foreign exchange gains or losses on settlement of intercompany transactions have no impact on Cash Flow.
- (5) Per Common Share – diluted.

FOREIGN EXCHANGE

As disclosed in the Business Environment section of this MD&A, the average U.S./Canadian dollar exchange rate increased 1 percent to \$0.938 in 2008 compared to \$0.930 in 2007. The table below summarizes the quarterly and total year impacts of these changes on EnCana's operations when compared to the same periods in the prior years.

	2008	Q4	Q3	Q2	Q1	2007
Average U.S./Canadian Dollar Exchange Rate	\$ 0.938	\$ 0.825	\$ 0.961	\$ 0.990	\$ 0.996	\$ 0.930
Change from comparative period in prior year	0.008	(0.194)	0.004	0.079	0.142	0.048
Increase (decrease) in:						
(\$ millions)						
Capital Investment	\$ 10	\$ (212)	\$ 2	\$ 57	\$ 163	\$ 199
Operating Expense	11	(63)	1	24	48	68
Administrative Expense	4	(17)	1	6	14	18
DD&A Expense	16	(127)	2	51	90	130
(\$/Mcfe)						
Operating Expense	0.01	(0.15)	—	0.06	0.13	0.04
Administrative Expense	—	(0.04)	—	0.01	0.04	0.01

RESULTS OF OPERATIONS

Production Volumes

	2008	Q4	Q3	Q2	Q1	2007	Q4	Q3	Q2	Q1	2006
Produced Gas (MMcf/d)											
Canadian Plains	842	820	831	856	860	875	876	858	874	891	906
Canadian Foothills	1,300	1,302	1,351	1,289	1,256	1,255	1,313	1,280	1,231	1,196	1,166
USA	1,633	1,677	1,674	1,629	1,552	1,345	1,464	1,387	1,303	1,222	1,182
Integrated Oil – Other ⁽¹⁾	63	59	61	67	65	91	69	105	98	91	113
	3,838	3,858	3,917	3,841	3,733	3,566	3,722	3,630	3,506	3,400	3,367
Crude Oil (bbls/d) ⁽²⁾											
Canadian Plains	66,157	64,990	64,789	65,097	69,781	70,940	70,287	70,711	70,148	72,639	75,612
Canadian Foothills	8,473	8,437	8,217	8,376	8,867	8,216	8,441	7,978	7,959	8,489	9,037
Foster Creek/ Christina Lake	30,183	35,068	31,547	24,671	29,376	26,814	27,190	28,740	27,994	23,269	42,768
Integrated Oil – Other ⁽¹⁾	2,729	2,133	2,273	3,009	3,514	2,688	3,040	2,235	2,489	2,990	5,185
	107,542	110,628	106,826	101,153	111,538	108,658	108,958	109,664	108,590	107,387	132,602
NGLs (bbls/d) ⁽²⁾											
Canadian Plains	1,181	1,126	1,147	1,189	1,262	1,260	1,422	1,209	1,206	1,203	1,380
Canadian Foothills	11,507	11,265	11,730	11,779	11,256	10,056	10,966	9,932	9,811	9,497	10,333
USA	13,350	12,831	13,853	13,482	13,232	14,180	14,791	15,578	13,809	12,503	12,958
	26,038	25,222	26,730	26,450	25,750	25,496	27,179	26,719	24,826	23,203	24,671
Continuing Operations (MMcfe/d) ⁽³⁾											
	4,639	4,673	4,718	4,607	4,557	4,371	4,539	4,448	4,306	4,184	4,311
Discontinued Operations Ecuador (bbls/d) ⁽⁴⁾											
	–	–	–	–	–	–	–	–	–	–	11,996
Discontinued Operations (MMcfe/d) ⁽³⁾											
	–	–	–	–	–	–	–	–	–	–	72
Total (MMcfe/d) ⁽³⁾											
	4,639	4,673	4,718	4,607	4,557	4,371	4,539	4,448	4,306	4,184	4,383

(1) Volumes related to operating areas outside of Foster Creek and Christina Lake including Athabasca (gas) and Senlac (crude oil).

(2) Crude oil and NGLs production in 2007 and 2006 were restated in the second quarter of 2008 to reflect the reclassification of oil to NGLs in the USA.

(3) Liquids converted to thousand cubic feet equivalent at 1 barrel = 6 thousand cubic feet.

(4) Ecuador interests sold on February 28, 2006.

Key Resource Plays

	Daily Production				Drilling Activity (net wells drilled)			
	2008	2008 vs 2007		2007	2007 vs 2006	2006	2008	2007
Natural Gas (MMcf/d)								
Jonah	603	8%	557	20%	464	175	135	163
Piceance	385	11%	348	7%	326	328	286	220
East Texas	334	134%	143	44%	99	78	35	59
Fort Worth	142	15%	124	23%	101	83	75	97
Greater Sierra	220	4%	211	-1%	213	106	109	115
Cutbank Ridge ⁽¹⁾	296	15%	258	37%	189	82	93	134
Bighorn ⁽¹⁾	167	33%	126	30%	97	64	62	58
CBM	304	17%	259	34%	194	698	1,079	729
Shallow Gas	700	-4%	726	-2%	739	1,195	1,914	1,310
	3,151	14%	2,752	14%	2,422	2,809	3,788	2,885
Oil (bbls/d)								
Foster Creek ⁽²⁾	25,947	7%	24,262	31%	18,455	20	23	3
Christina Lake ⁽²⁾	4,236	66%	2,552	-13%	2,929	-	3	1
	30,183	13%	26,814	25%	21,384	20	26	4
Pelican Lake	21,975	-5%	23,253	-1%	23,562	-	-	-
Weyburn	14,031	-5%	14,771	-2%	15,132	21	37	35
	66,189	2%	64,838	8%	60,078	41	63	39
Total (MMcfe/d) ⁽³⁾	3,548	13%	3,141	13%	2,782	2,850	3,851	2,924

- (1) Key resource play production and wells drilled information in 2007 and 2006 for Cutbank Ridge and Bighorn were restated in the first quarter of 2008 to include the addition of new areas and zones that now qualify for key resource play inclusion based on EnCana's internal criteria.
- (2) Key resource play production and wells drilled information in 2006 have been adjusted on a pro forma basis to reflect the 50 percent contribution of Foster Creek and Christina Lake to the business venture with ConocoPhillips in 2007.
- (3) Total key resource play production and wells drilled information in 2007 and 2006 were restated in the first quarter of 2008 to include the designation of Weyburn as an oil key resource play.

Production volumes increased 6 percent or 268 MMcfe/d in 2008 compared to 2007 due to increased production from EnCana's natural gas key resource plays of 14 percent and oil key resource plays of 2 percent offset partially by natural declines in conventional properties and the volume impact of minor property divestitures.

CANADIAN PLAINS

PRODUCED GAS

Financial Results

	2008		2007		2006
(\$ millions, except per unit amounts in \$ per thousand cubic feet)		\$/Mcf		\$/Mcf	
Canadian Plains					
Revenues, Net of Royalties/Price	\$ 2,392	\$ 7.77	\$ 1,946	\$ 6.10	\$ 2,021
Realized Financial Hedging Gain (Loss)	(91)		240		192
Expenses					
Production and mineral taxes	36	0.12	34	0.11	41
Transportation and selling	71	0.23	82	0.26	77
Operating	241	0.78	221	0.69	194
Operating Cash Flow/Netback ⁽¹⁾	\$ 1,953	\$ 6.64	\$ 1,849	\$ 5.04	\$ 1,901
Netback including Realized Financial Hedging		\$ 6.35		\$ 5.79	
Gas Production Volumes (MMcf/d)		842		875	
					906

(1) Netback excludes the impact of realized financial hedging.

Produced Gas Revenue Variances

(\$ millions)	2007 Revenues Net of Royalties	Revenue Variances in:		2008 Revenues Net of Royalties
		Price ⁽¹⁾	Volume	
Canadian Plains	\$ 2,186	\$ 199	\$ (84)	\$ 2,301

(1) Includes the impact of realized financial hedging.

2008 Versus 2007

Revenues, net of royalties, increased in 2008 compared to 2007 due to:

- A 27 percent increase in natural gas prices, excluding the impact of financial hedging;

offset by:

- Realized financial hedging losses of \$91 million or \$0.29 per Mcf in 2008 compared to gains of \$240 million or \$0.75 per Mcf in 2007; and
- A 4 percent decrease in natural gas production volumes. Production added as a result of infill drilling and recompletion programs were offset by expected natural declines for the Shallow Gas key resource play and conventional properties.

The increase in Canadian Plains natural gas price in 2008, excluding the impact of financial hedges, reflects the changes in AECO and NYMEX benchmark prices and changes in the basis differentials. Realized natural gas prices also reflect the variability caused by relative prices and volume weightings at given sales points.

Natural gas per unit operating expenses for the Canadian Plains in 2008 were 13 percent or \$0.09 per Mcf higher than in 2007 primarily as a result of higher property tax and lease costs, workovers and repairs and maintenance offset by lower long-term compensation costs due to the change in the EnCana share price. In addition, with a relatively high proportion of fixed costs, lower production volumes also contributed to increased per unit costs.

2007 Versus 2006

Revenues, net of royalties, decreased in 2007 compared to 2006 due to:

- A 3 percent decrease in natural gas production volumes. Production added as a result of infill drilling and recompletion programs was offset by natural declines for the Shallow Gas key resource play and conventional properties;
- offset by:
- Realized financial hedging gains of \$240 million or \$0.75 per Mcf in 2007 compared to gains of \$192 million or \$0.58 per Mcf in 2006.

Canadian Plains natural gas price in 2007, excluding the impact of financial hedges, remained relatively unchanged from 2006 and reflects the changes in AECO and NYMEX benchmark prices and changes in the basis differentials.

Natural gas per unit operating expenses for the Canadian Plains in 2007 were 17 percent or \$0.10 per Mcf higher than in 2006 as a result of the higher U.S./Canadian dollar exchange rate, higher long-term compensation costs, increased property tax and lease costs and higher repairs and maintenance expenses offset partially by decreased electricity costs due to lower electricity prices.

CRUDE OIL AND NGLS

Financial Results

(\$ millions)		2008	2007	2006
Canadian Plains				
Revenues, Net of Royalties		\$ 2,106	\$ 1,453	\$ 1,337
Expenses				
Production and mineral taxes		38	29	31
Transportation and selling		321	263	276
Operating		239	215	188
Operating Cash Flow		\$ 1,508	\$ 946	\$ 842

Crude Oil and NGLs Revenue Variances

(\$ millions)	2007 Revenues Net of Royalties	Revenue Variances in:			2008 Revenues Net of Royalties
		Price ⁽¹⁾	Volume	Other ⁽²⁾	
Canadian Plains	\$ 1,453	\$ 702	\$ (101)	\$ 52	\$ 2,106

(1) Includes the impact of realized financial hedging.

(2) Revenue dollars reported include the value of condensate sold as bitumen blend. Condensate costs are recorded in transportation and selling expense.

2008 Versus 2007

Revenues, net of royalties, increased in 2008 compared to 2007 due to:

- A 59 percent increase in crude oil prices and 32 percent increase in NGLs prices, excluding financial hedges; offset by:
- Realized financial hedging losses on liquids of \$150 million or \$6.02 per bbl in 2008 compared to losses of \$87 million or \$3.32 per bbl in 2007.

Production from the Pelican Lake key resource play in 2008 was 21,975 bbls/d, down 5 percent compared to 2007 due primarily to plant down time and treating issues. Production from the Weyburn key resource play of 14,031 bbls/d was down 5 percent mainly due to expected natural declines offset by production additions from the infill drilling program. At Suffield, production of 12,971 bbls/d was down 17 percent mainly due to natural declines and the delay in well tie-ins. Overall, Canadian Plains crude oil production decreased 7 percent.

2007 Versus 2006

Revenues, net of royalties, increased in 2007 compared to 2006 due to:

- A 15 percent increase in crude oil prices and 17 percent increase in NGLs prices, excluding financial hedges; and
- Realized financial hedging losses on liquids of \$87 million or \$3.32 per bbl in 2007 compared to losses of \$100 million or \$3.67 per bbl in 2006;

offset by:

- A 6 percent decrease in crude oil production volumes primarily due to natural declines in production from conventional properties. Production from the key resource plays of Pelican Lake and Weyburn remained relatively unchanged year-over-year while production of 15,563 bbls/d at Suffield was down 10 percent from 2006.

Per Unit Results – Crude Oil

(\$ per barrel)	2008	2007	2006
Canadian Plains			
Price ⁽¹⁾⁽²⁾	\$ 79.09	\$ 49.62	\$ 43.31
Expenses			
Production and mineral taxes	1.57	1.11	1.17
Transportation and selling	1.41	1.24	0.79
Operating	9.74	8.33	7.03
Netback	\$ 66.37	\$ 38.94	\$ 34.32
Crude Oil Production Volumes (bbls/d)	66,157	70,940	75,612

(1) Excludes the impact of realized financial hedging.

(2) Represents blend sales price net of purchased condensate costs.

2008 Versus 2007

Canadian Plains crude oil prices increased in 2008 as a result of the changes in benchmark WTI and WCS crude oil prices as well as lower average differentials. Total realized financial hedging losses on crude oil for Canadian Plains were approximately \$147 million or \$6.02 per bbl in 2008 compared to losses of approximately \$85 million or \$3.31 per bbl in 2007.

Crude oil per unit production and mineral taxes for the Canadian Plains increased 41 percent or \$0.46 per bbl in 2008 compared to 2007 primarily due to higher crude oil prices.

Crude oil per unit transportation and selling costs for the Canadian Plains increased 14 percent or \$0.17 per bbl in 2008 compared to 2007 due to additional clean oil trucking costs at Pelican Lake offset by lower clean oil trucking costs at Weyburn.

Crude oil per unit operating costs for the Canadian Plains in 2008 increased 17 percent or \$1.41 per bbl compared to 2007 mainly due to increased workovers, property tax and lease costs, salaries and benefits and chemical costs combined with lower overall crude oil volumes offset by lower long-term compensation costs due to the change in the EnCana share price.

2007 Versus 2006

Canadian Plains crude oil prices in 2007 increased 15 percent compared to 2006. This increase reflects the changes in benchmark WTI and WCS crude oil prices. Total realized financial hedging losses on crude oil were approximately \$85 million or \$3.31 per bbl in 2007 compared to losses of approximately \$98 million or \$3.68 per bbl in 2006.

Crude oil per unit transportation and selling costs for the Canadian Plains increased 57 percent or \$0.45 per bbl in 2007 compared to 2006 due to increased clean oil trucking costs at Weyburn and the higher U.S./Canadian dollar exchange rate.

Crude oil per unit operating costs for the Canadian Plains in 2007 increased 18 percent or \$1.30 per bbl compared to 2006 mainly due to the higher U.S./Canadian dollar exchange rate, increased workovers, higher long-term compensation costs and increased chemicals offset partially by decreased electricity costs due to lower electricity prices.

Per Unit Results – NGLs

NGLs are a byproduct obtained through the production of natural gas. As a result, operating costs associated with the production of NGLs are included with produced gas.

2008 Versus 2007

NGLs production volumes were 1,181 bbls/d in 2008 compared to 1,260 bbls/d in 2007, which is consistent with declining gas production. NGLs prices increased 32 percent to \$78.91 per bbl in 2008 from \$59.98 per bbl in 2007, which is consistent with the higher WTI benchmark price.

2007 Versus 2006

NGLs production volumes were 1,260 bbls/d in 2007 compared to 1,380 bbls/d in 2006, which is consistent with declining gas production. NGLs prices increased 17 percent to \$59.98 per bbl in 2007 compared to \$51.10 per bbl in 2006, which is consistent with the higher WTI benchmark price.

CANADIAN FOOTHILLS

PRODUCED GAS

Financial Results

	2008		2007		2006
(\$ millions, except per unit amounts in \$ per thousand cubic feet)		\$/Mcf		\$/Mcf	
Canadian Foothills					
Revenues, Net of Royalties/Price	\$ 3,862	\$ 8.12	\$ 2,885	\$ 6.30	\$ 2,681
Realized Financial Hedging Gain (Loss)	(142)		347		255
Expenses					
Production and mineral taxes	28	0.06	36	0.08	39
Transportation and selling	201	0.42	192	0.42	186
Operating	549	1.15	482	1.05	394
Operating Cash Flow/Netback ⁽¹⁾	\$ 2,942	\$ 6.49	\$ 2,522	\$ 4.75	\$ 2,317
Netback including Realized Financial Hedging		\$ 6.19		\$ 5.51	
Gas Production Volumes (MMcf/d)		1,300		1,255	
					1,166

(1) Netback excludes the impact of realized financial hedging.

Produced Gas Revenue Variances

(\$ millions)	2007 Revenues Net of Royalties	Revenue Variances in:		2008 Revenues Net of Royalties
		Price ⁽¹⁾	Volume	
Canadian Foothills	\$ 3,232	\$ 349	\$ 139	\$ 3,720

(1) Includes the impact of realized financial hedging.

2008 Versus 2007

Revenues, net of royalties, increased in 2008 compared to 2007 due to:

- A 29 percent increase in natural gas prices, excluding the impact of financial hedging; and
- A 4 percent increase in natural gas production volumes;

offset by:

- Realized financial hedging losses of \$142 million or \$0.30 per Mcf in 2008 compared to gains of \$347 million or \$0.76 per Mcf in 2007.

Produced gas volumes in the Canadian Foothills increased in 2008 due to drilling success as well as increased tie-in and completion activity in the key resource plays of CBM, Bighorn and Cutbank Ridge offset partially by natural declines for conventional properties.

The increase in Canadian Foothills natural gas price in 2008, excluding the impact of financial hedges, reflects the changes in AECO and NYMEX benchmark prices and changes in the basis differentials. Realized natural gas prices also reflect the variability caused by relative prices and volume weightings at given sales points.

Natural gas per unit operating expenses for the Canadian Foothills in 2008 were 10 percent or \$0.10 per Mcf higher than in 2007 primarily as a result of higher repairs and maintenance due to scheduled plant turnarounds, increased gathering and processing, salaries and benefits, workovers, property tax and lease costs offset by lower long-term compensation costs due to the change in the EnCana share price.

2007 Versus 2006

Revenues, net of royalties, increased in 2007 compared to 2006 due to:

- Realized financial hedging gains of \$347 million or \$0.76 per Mcf in 2007 compared to gains of \$255 million or \$0.60 per Mcf in 2006; and
- An 8 percent increase in Canadian Foothills natural gas production volumes.

Produced gas volumes in the Canadian Foothills increased in 2007 as a result of drilling success and new facilities in the key resource plays of CBM, Cutbank Ridge and Bighorn offset partially by natural declines for conventional properties.

The change in Canadian Foothills natural gas prices in 2007, excluding the impact of financial hedges, reflects the changes in AECO and NYMEX benchmark prices and changes in the basis differentials. Realized natural gas prices also reflect the variability caused by relative prices and volume weightings at given sales points.

Natural gas per unit operating expenses for the Canadian Foothills in 2007 were 14 percent or \$0.13 per Mcf higher than in 2006 as a result of the higher U.S./Canadian dollar exchange rate, higher repairs and maintenance expenses and increased property tax and lease costs offset partially by decreased electricity costs. Operating costs were also impacted by higher long-term compensation costs in 2007 compared to 2006 due to the change in the EnCana share price.

CRUDE OIL AND NGLs

Financial Results

(\$ millions)	2008	2007	2006
Canadian Foothills			
Revenues, Net of Royalties	\$ 578	\$ 390	\$ 360
Expenses			
Production and mineral taxes	5	3	4
Transportation and selling	12	9	8
Operating	39	33	34
Operating Cash Flow	\$ 522	\$ 345	\$ 314

Crude Oil and NGLs Revenue Variances

(\$ millions)	2007 Revenues Net of Royalties	Revenue Variances in:		2008 Revenues Net of Royalties
		Price ⁽¹⁾	Volume	
Canadian Foothills	\$ 390	\$ 138	\$ 50	\$ 578

(1) Includes the impact of realized financial hedging.

2008 Versus 2007

Revenues, net of royalties, increased in 2008 compared to 2007 due to:

- A 42 percent increase in crude oil prices and 35 percent increase in NGLs prices, excluding financial hedges; offset by:
 - Realized financial hedging losses on liquids of \$44 million or \$6.08 per bbl in 2008 compared to losses of \$23 million or \$3.37 per bbl in 2007.

2007 Versus 2006

Revenues, net of royalties, increased in 2007 compared to 2006 due to:

- A 12 percent increase in crude oil prices and 16 percent increase in NGLs prices, excluding financial hedges; and
- Realized financial hedging losses on liquids of \$23 million or \$3.37 per bbl in 2007 compared to losses of \$25 million or \$3.57 per bbl in 2006.

Per Unit Results – Crude Oil

(\$ per barrel)	2008	2007	2006
Canadian Foothills			
Price ⁽¹⁾	\$ 91.78	\$ 64.63	\$ 57.74
Expenses			
Production and mineral taxes	1.48	1.05	1.27
Transportation and selling	2.07	1.77	1.41
Operating	12.75	10.84	10.21
Netback	\$ 75.48	\$ 50.97	\$ 44.85
Crude Oil Production Volumes (bbls/d)	8,473	8,216	9,037

(1) Excludes the impact of realized financial hedging.

2008 Versus 2007

Canadian Foothills crude oil prices increased in 2008 as a result of the changes in benchmark WTI and WCS crude oil prices as well as lower average differentials. Total realized financial hedging losses on crude oil for Canadian Foothills were approximately \$18 million or \$5.93 per bbl in 2008 compared to losses of approximately \$10 million or \$3.32 per bbl in 2007.

Canadian Foothills crude oil per unit production and mineral taxes increased 41 percent or \$0.43 per bbl in 2008 compared to 2007 primarily due to higher crude oil prices.

Canadian Foothills crude oil per unit transportation and selling increased 17 percent or \$0.30 per bbl in 2008 compared to 2007 primarily due to higher transportation rates.

Canadian Foothills crude oil per unit operating costs in 2008 increased 18 percent or \$1.91 per bbl compared to 2007 mainly due to higher electricity, repairs and maintenance and chemicals costs offset by lower purchased fuel costs.

2007 Versus 2006

Canadian Foothills crude oil prices increased in 2007 as a result of the changes in benchmark WTI and WCS crude oil prices offset partially by higher average differentials. Total realized financial hedging losses on crude oil for Canadian Foothills were approximately \$10 million or \$3.32 per bbl in 2007 compared to losses of approximately \$12 million or \$3.58 per bbl in 2006.

Canadian Foothills crude oil per unit production and mineral taxes decreased 17 percent or \$0.22 per bbl in 2007 compared to 2006 primarily due to lower royalty income volumes in 2007 compared to 2006.

Canadian Foothills crude oil per unit transportation and selling costs increased 26 percent or \$0.36 per bbl in 2007 compared to 2006 due to the higher U.S./Canadian dollar exchange rate and additional marketing costs.

Canadian Foothills crude oil per unit operating costs in 2007 increased 6 percent or \$0.63 per bbl compared to 2006 mainly due to the higher U.S./Canadian dollar exchange rate, increased workovers, property tax and lease costs offset partially by lower gathering and processing and electricity costs.

Per Unit Results – NGLs

NGLs are a byproduct obtained through the production of natural gas. As a result, operating costs associated with the production of NGLs are included with produced gas.

2008 Versus 2007

NGLs production volumes were 11,507 bbls/d in 2008 compared to 10,056 bbls/d in 2007. Average NGLs prices increased 35 percent to \$80.22 per bbl in 2008 from \$59.26 per bbl in 2007, which is consistent with the higher WTI benchmark price.

2007 Versus 2006

NGLs production volumes were 10,056 bbls/d in 2007 compared to 10,333 bbls/d in 2006. Average NGLs prices increased 16 percent to \$59.26 per bbl in 2007 from \$51.12 per bbl in 2006, which is consistent with the higher WTI benchmark price.

USA

PRODUCED GAS

Financial Results

	2008		2007		2006	
({\$ millions, except per unit amounts in \$ per thousand cubic feet})		\$/Mcf		\$/Mcf	.	\$/Mcf
USA						
Revenues, Net of Royalties/Price	\$ 4,718	\$ 7.89	\$ 2,641	\$ 5.38	\$ 2,742	\$ 6.35
Realized Financial Hedging Gain (Loss)	216		1,124		112	
Expenses						
Production and mineral taxes	334	0.56	167	0.34	213	0.49
Transportation and selling	502	0.84	307	0.62	248	0.54
Operating	352	0.59	323	0.65	283	0.65
Operating Cash Flow/Netback ⁽¹⁾	\$ 3,746	\$ 5.90	\$ 2,968	\$ 3.77	\$ 2,110	\$ 4.67
Netback including Realized Financial Hedging		\$ 6.26		\$ 6.06		\$ 4.93
Gas Production Volumes (MMcf/d)		1,633		1,345		1,182

(1) Netback excludes the impact of realized financial hedging.

Produced Gas Revenue Variances

(\$ millions)	2007 Revenues Net of Royalties	Revenue Variances in:		2008 Revenues Net of Royalties
		Price ⁽¹⁾	Volume	
USA	\$ 3,765	\$ 288	\$ 881	\$ 4,934

(1) Includes the impact of realized financial hedging.

2008 Versus 2007

Revenues, net of royalties, increased in 2008 compared to 2007 due to:

- A 47 percent increase in natural gas prices, excluding the impact of financial hedging; and
- A 21 percent increase in natural gas production volumes;

offset by:

- Realized financial hedging gains of \$216 million or \$0.36 per Mcf in 2008 compared to gains of \$1,124 million or \$2.29 per Mcf in 2007.

Produced gas volumes in the USA increased in 2008 as a result of drilling and operational success at East Texas, Jonah, Piceance and Fort Worth as well as incremental volumes from the Deep Bossier acquisition and upgrades to the compression and gathering facilities at Jonah. These increases were slightly offset by the impact of shut-in production (approximately 100 MMcf/d) at Piceance and Jonah during the fourth quarter of 2008 due to the low price environment.

The increase in USA natural gas prices in 2008, excluding the impact of financial hedges, reflects the changes in NYMEX and Rockies (Opal) benchmark prices and changes in the basis differentials. Realized natural gas prices also reflect the variability caused by relative prices and volume weightings at given sales points.

Natural gas per unit production and mineral taxes in the USA increased 65 percent or \$0.22 per Mcf in 2008 compared to 2007 primarily as a result of higher natural gas prices.

Natural gas per unit transportation and selling costs for the USA increased 35 percent or \$0.22 per Mcf in 2008 compared to 2007 as a result of higher unutilized transportation commitments as well as transporting gas greater distances on the Rockies Express Pipeline to improve price realizations.

Natural gas per unit operating expenses for the USA in 2008 were 9 percent lower or \$0.06 per Mcf lower than in 2007 due to a high proportion of fixed costs spread over increased production volumes and lower long-term compensation costs offset slightly by increased salaries and benefits, water disposal, repairs and maintenance and workover costs.

2007 Versus 2006

Revenues, net of royalties, increased in 2007 compared to 2006 due to:

- Realized financial hedging gains of \$1,124 million or \$2.29 per Mcf in 2007 compared to gains of \$112 million or \$0.26 per Mcf in 2006; and
- A 14 percent increase in natural gas production volumes;

offset by:

- A 15 percent decrease in natural gas prices, excluding the impact of financial hedging.

Produced gas volumes in the USA increased in 2007 as a result of drilling and operational success as well as new facilities at Jonah, East Texas, Fort Worth and Piceance. Fourth quarter 2007 produced gas volumes in the USA also benefited slightly from incremental volumes from the Deep Bossier acquisition (approximately 34 MMcf/d).

The change in USA natural gas prices in 2007, excluding the impact of financial hedges, reflects the changes in NYMEX and Rockies (Opal) benchmark prices and changes in the basis differentials. Realized natural gas prices also reflect the variability caused by relative prices and volume weightings at given sales points.

Natural gas per unit production and mineral taxes in the USA decreased 31 percent or \$0.15 per Mcf in 2007 compared to 2006 mainly as a result of lower natural gas prices in the U.S. Rockies and a reduction in the severance and ad valorem effective tax rate for Colorado properties.

Natural gas per unit transportation and selling costs for the USA increased 15 percent or \$0.08 per Mcf in 2007 compared to 2006 primarily as a result of higher transportation rates in the Piceance area.

CRUDE OIL AND NGLs

All of EnCana's liquids production in the USA relates to NGLs.

Financial Results

(\$ millions)	2008	2007	2006
USA			
Revenues, Net of Royalties	\$ 407	\$ 309	\$ 267
Expenses			
Production and mineral taxes	36	22	20
Operating Cash Flow	\$ 371	\$ 287	\$ 247

Crude Oil and NGLs Revenue Variances

(\$ millions)	2007 Revenues Net of Royalties	Revenue Variances in:		2008 Revenues Net of Royalties
		Price ⁽¹⁾	Volume	
USA	\$ 309	\$ 122	\$ (24)	\$ 407

(1) Includes the impact of realized financial hedging.

Per Unit Results – NGLs

NGLs are a byproduct obtained through the production of natural gas. As a result, operating costs associated with the production of NGLs are included with produced gas.

2008 Versus 2007

NGLs production volumes were 13,350 bbls/d in 2008 compared to 14,180 bbls/d in 2007. Average NGLs prices increased 39 percent to \$83.18 per bbl in 2008 from \$59.83 per bbl in 2007, which is consistent with the higher WTI benchmark price.

2007 Versus 2006

NGLs production volumes were 14,180 bbls/d in 2007 compared to 12,958 bbls/d in 2006. Average NGLs prices increased 6 percent to \$59.83 per bbl in 2007 from \$56.33 per bbl in 2006, which is consistent with the higher WTI benchmark price.

INTEGRATED OIL

FOSTER CREEK/CHRISTINA LAKE OPERATIONS

On January 2, 2007, EnCana became a 50 percent partner in an integrated North American oil business with ConocoPhillips that consists of an upstream and a downstream entity. The upstream entity includes contributed assets from EnCana, primarily the Foster Creek and Christina Lake oil properties while the downstream entity includes ConocoPhillips' Wood River and Borger refineries located in Illinois and Texas, respectively.

The current plan of the upstream business is to increase production capacity at Foster Creek/Christina Lake to approximately 218,000 bbls/d of bitumen with the completion of current expansion phases.

Financial Results

(\$ millions)	2008	2007	2006
Foster Creek/Christina Lake			
Revenues, Net of Royalties	\$ 1,117	\$ 738	\$ 941
Expenses			
Transportation and selling	526	366	476
Operating	170	159	194
Operating Cash Flow	\$ 421	\$ 213	\$ 271

Crude Oil Revenue Variances

(\$ millions)	2007 Revenues Net of Royalties	Revenue Variances in:			2008 Revenues Net of Royalties
		Price ⁽¹⁾	Volume	Other ⁽²⁾	
Foster Creek/Christina Lake	\$ 738	\$ 217	\$ (4)	\$ 166	\$ 1,117

(1) Includes the impact of realized financial hedging.

(2) Revenue dollars reported include the value of condensate sold as bitumen blend. Condensate costs are recorded in transportation and selling expense.

2008 Versus 2007

Revenues, net of royalties, increased in 2008 compared to 2007 due to:

- An increase in crude oil prices, excluding financial hedges;
- An increase in average condensate prices; and
- Relatively unchanged crude oil sales volumes attributable to a 13 percent increase in production volumes offset by changes in inventory levels;

offset by:

- Realized financial hedging losses of \$67 million or \$6.11 per bbl in 2008 compared to losses of \$43 million or \$3.88 per bbl in 2007.

2007 Versus 2006

Revenues, net of royalties, decreased in 2007 compared to 2006 due to:

- A 37 percent decrease in Foster Creek/Christina Lake crude oil production volumes as a result of the joint venture with ConocoPhillips partially offset by a 10 percent increase in crude oil prices, excluding financial hedges. Production volumes on a pro forma basis, after reflecting 100 percent of Foster Creek and Christina Lake production, grew 25 percent to 53,628 bbls/d in 2007 compared to 2006; and
- Lower condensate purchased for bitumen blending at Foster Creek/Christina Lake as a result of the joint venture with ConocoPhillips;

offset by:

- Realized financial hedging losses of \$43 million or \$3.88 per bbl in 2007 compared to losses of \$62 million or \$3.98 per bbl in 2006.

Per Unit Results – Crude Oil

(\$ per barrel)	2008	2007	2006
Foster Creek/Christina Lake			
Price ⁽¹⁾⁽²⁾⁽³⁾	\$ 62.44	\$ 40.14	\$ 36.49
Expenses			
Transportation and selling	2.36	2.88	2.64
Operating	15.53	14.46	12.38
Netback	\$ 44.55	\$ 22.80	\$ 21.47
Crude Oil Production Volumes (bbls/d)	30,183	26,814	42,768
Pro forma Production Volumes (bbls/d) ⁽⁴⁾	30,183	26,814	21,384

(1) Excludes the impact of realized financial hedging.

(2) Represents blend sales price net of purchased condensate costs.

(3) 2008 price includes a reduction of \$4.26 per barrel related to the impact of a write-down to net realizable value of condensate inventories (2007 – nil; 2006 – nil).

(4) 2006 production volumes adjusted on a pro forma basis to reflect the 50 percent contribution of Foster Creek and Christina Lake to the business venture with ConocoPhillips in 2007.

2008 Versus 2007

Foster Creek/Christina Lake crude oil prices increased in 2008 as a result of the changes in benchmark WTI and WCS crude oil prices as well as lower average differentials. WCS as a percentage of WTI was 80 percent in 2008 compared to 68 percent in 2007.

Foster Creek/Christina Lake crude oil per unit transportation and selling costs in 2008 decreased 18 percent or \$0.52 per bbl compared to 2007 due to variability in sales destinations and pipelines utilized to transport the product.

Foster Creek/Christina Lake crude oil per unit operating costs increased 7 percent or \$1.07 per bbl in 2008 compared to 2007. The increase is mainly due to increased workovers and staff levels offset by lower long-term compensation costs due to the change in the EnCana share price.

2007 Versus 2006

Foster Creek/Christina Lake crude oil prices in 2007 increased 10 percent compared to 2006. This increase reflects the changes in benchmark WTI and WCS crude oil prices compared to 2006.

Foster Creek/Christina Lake crude oil per unit transportation and selling costs in 2007 increased 9 percent or \$0.24 per bbl compared to 2006 due to a higher percentage of volumes being delivered to the U.S. Gulf Coast in 2007 compared to 2006 and the higher U.S./Canadian dollar exchange rate.

Foster Creek/Christina Lake crude oil per unit operating costs increased 17 percent or \$2.08 per bbl in 2007 compared to 2006. This reflected increased purchased fuel costs at Foster Creek to steam new well pairs prior to commencing production, increased repairs and maintenance, salaries and benefits and chemicals. In addition, operating costs for 2007 compared to 2006 were impacted by the higher U.S./Canadian dollar exchange rate and higher long-term compensation costs due to the change in the EnCana share price.

DOWNTREAM OPERATIONS

Financial Results

(\$ millions)	2008	2007
Revenues	\$ 9,011	\$ 7,315
Expenses		
Operating	492	428
Purchased product	8,760	5,813
Operating Cash Flow	\$ (241)	\$ 1,074

The downstream business commenced on January 2, 2007 when EnCana became a 50 percent partner in the entity that owns the Wood River and Borger refineries operated by ConocoPhillips.

The Wood River refinery, located in Roxana, Illinois, has a current capacity of approximately 306,000 bbls/d of crude oil (on a 100 percent basis). In the third quarter of 2008, the Wood River refinery received regulatory approvals to start construction on the Coker and Refinery Expansion ("CORE") project. EnCana's 50 percent share of the CORE project is expected to cost approximately \$1.8 billion and is anticipated to be completed and in full operation in 2011. The expansion is expected to increase crude oil refining capacity by 50,000 bbls/d to 356,000 bbls/d (on a 100 percent basis) and more than double heavy crude oil refining capacity to 240,000 bbls/d.

The Borger refinery, located in Borger, Texas, has a current capacity of approximately 146,000 bbls/d of crude oil and approximately 45,000 bbls/d of NGLs (on a 100 percent basis). The coker installed in 2007 is enabling the refinery to upgrade approximately 35,000 bbls/d of WCS heavy crude.

The current plan of the downstream business is to refine approximately 135,000 bbls/d of bitumen equivalent (on a 100 percent basis) to primarily motor fuels with the completion of the CORE project in 2011. As at December 31, 2008, the Wood River and Borger refineries have processing capability to refine up to approximately 70,000 bbls/d of bitumen equivalent (on a 100 percent basis).

The two refineries have a combined crude oil refining capacity of 452,000 bbls/d (on a 100 percent basis) and operated at an average 93 percent of that capacity during 2008 compared to 96 percent in 2007. Refinery crude utilization was lower in 2008 primarily due to unplanned refinery outages and maintenance activities at Wood River as well as crude oil supply disruptions resulting from hurricane activity in the Gulf Coast. Refined products averaged 448,000 bbls/d (224,000 bbls/d net to EnCana) in 2008 compared to 457,000 bbls/d (228,500 bbls/d net to EnCana) in 2007.

Revenues reflect EnCana's 50 percent share of the sale of refined petroleum products in the United States. Operating Cash Flow from downstream operations in 2008 decreased \$1,315 million compared to 2007. Weaker refining margins as evidenced by the 37 percent decrease in Chicago 3-2-1 crack spreads combined with a 3 percent decline in capacity utilization accounted for approximately \$825 million of the decrease in Operating Cash Flow.

Pursuant to Canadian GAAP, the Company uses the First In, First Out ("FIFO") method of inventory valuation. The 50 percent drop in WTI prices during the fourth quarter of 2008 compared to the third quarter of 2008 resulted in much lower inventory values at year-end and therefore much higher purchased product costs. This decreased Operating Cash Flow by \$192 million compared to an increase of \$159 million in 2007. In addition, as a result of low crude oil and refined product prices at year-end, a \$95 million write-down of inventory values to net realizable value was recorded.

Purchased products, consisting mainly of crude oil, represented 95 percent of total expenses in 2008 compared to 93 percent in 2007. Operating costs for labour, utilities and supplies comprised the balance of expenses. Revenues and purchased product have increased 23 percent and 51 percent in 2008, respectively, in line with the significant increase in crude oil prices and reduced refining margins.

OTHER INTEGRATED OIL OPERATIONS

In addition to the 50 percent owned Foster Creek/Christina Lake operations, Integrated Oil also manages the 100 percent owned natural gas operations in Athabasca and crude oil operations in Senlac.

2008 Versus 2007

Production volumes from Athabasca were 63 MMcf/d in 2008 compared to 91 MMcf/d in 2007 and from Senlac were 2,729 bbls/d in 2008 compared to 2,688 bbls/d in 2007. The decrease at Athabasca is due to increased internal usage to supply a portion of the fuel gas requirements at Foster Creek and expected natural declines.

2007 Versus 2006

Production volumes from Athabasca were 91 MMcf/d in 2007 compared to 113 MMcf/d in 2006 and from Senlac were 2,688 bbls/d in 2007 compared to 5,185 bbls/d in 2006. These decreases are due to expected natural declines.

DEPRECIATION, DEPLETION AND AMORTIZATION

UPSTREAM DD&A

EnCana uses full cost accounting and calculates DD&A on a country-by-country cost centre basis.

2008 Versus 2007

Upstream DD&A expenses of \$3,889 million in 2008 increased \$410 million or 12 percent compared to 2007 due to:

- Production volumes increased 6 percent; and
- DD&A rates in 2008 for the USA were higher than 2007 primarily due to higher capitalized costs, mainly attributable to the Deep Bossier acquisition. DD&A rates in Canada for 2008 were lower than 2007 primarily as a result of the higher proved reserves.

2007 Versus 2006

Upstream DD&A expenses of \$3,479 million in 2007 increased \$464 million or 15 percent compared to 2006 due to:

- North American production volumes increased 1 percent; and
- DD&A rates in 2007 were higher than 2006 primarily as a result of increased future development costs and the higher U.S./Canadian dollar exchange rate.

DOWNSTREAM DD&A

EnCana calculates DD&A on a straight-line basis over estimated service lives of approximately 25 years.

Downstream refining DD&A was \$188 million in 2008 compared to \$159 million in 2007 as a result of a full year of depreciation on prior year capital additions, as well as accelerated depreciation on certain assets expected to be retired sooner than originally anticipated.

MARKET OPTIMIZATION

Financial Results

(\$ millions)	2008	2007	2006
Revenues	\$ 2,655	\$ 2,944	\$ 3,007
Expenses			
Transportation and selling	—	10	16
Operating	45	37	62
Purchased product	2,577	2,858	2,862
Operating Cash Flow	33	39	67
Depreciation, depletion and amortization	15	17	12
Segment Income	\$ 18	\$ 22	\$ 55

Market Optimization revenues and purchased product expenses relate to activities that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification that enhance the sale of EnCana's production.

2008 Versus 2007

Revenues and purchased product expenses decreased in 2008 compared to 2007 mainly due to overall volume decreases required for Market Optimization offset partially by increased pricing.

2007 Versus 2006

Revenues and purchased product expenses were basically flat in 2007 compared to 2006, with slight decreases in prices being offset by increases in volumes required for optimization activities.

CORPORATE AND OTHER

Financial Results

(\$ millions)	2008	2007	2006
Revenues	\$ 2,719	\$ (1,239)	\$ 2,052
Expenses			
Operating	(13)	14	(1)
Depreciation, depletion and amortization	131	161	85
Segment Income (Loss)	\$ 2,601	\$ (1,414)	\$ 1,968

Revenues represent unrealized mark-to-market gains or losses related to financial natural gas and liquids hedge contracts.

DD&A includes provisions for corporate assets, such as computer equipment, office furniture and leasehold improvements, as well as for international assets. DD&A in 2008 included impairments of \$38 million related to exploration prospects in Qatar and France as a result of exiting these countries and in 2007 included impairments of \$68 million related to exploration prospects in France and Oman. DD&A in 2006 included impairments of \$6 million related to exploration prospects in the Middle East.

Consolidated Corporate and Other Expenses

(\$ millions)	2008	2007	2006
Administrative	\$ 473	\$ 384	\$ 271
Interest, net	586	428	396
Accretion of asset retirement obligation	79	64	50
Foreign exchange (gain) loss, net	423	(164)	14
(Gain) loss on divestitures	(140)	(65)	(323)

2008 Versus 2007

Administrative expenses increased \$89 million in 2008 compared to 2007 primarily due to higher staff levels and other related costs as a result of growth, one time charges for settlements of a lawsuit and an arbitration ruling offset by lower long-term compensation costs of \$93 million as a result of the change in the EnCana share price. The proposed corporate reorganization also added \$67 million of costs related to work needed to prepare for the transaction. Excluding these corporate reorganization costs, EnCana's administrative expenses were \$0.24 per Mcfe in 2008, which is unchanged from 2007. Fourth quarter administrative expenses decreased \$47 million in 2008 compared to 2007 primarily due to lower long-term compensation costs of \$83 million and lower costs of \$17 million due to the lower U.S./Canadian dollar exchange rate offset partially by \$24 million for the proposed corporate reorganization and other related costs due to growth.

Net interest expense in 2008 increased \$158 million compared to 2007 primarily as a result of higher weighted average outstanding debt in 2008. Weighted average debt for 2008 was impacted for the entire year as a result of the Deep Bossier acquisition, which occurred in November 2007, compared to weighted average debt for 2007, which was impacted by this acquisition for a relatively short period of time. EnCana's total long-term debt, including current portion, decreased \$538 million to \$9,005 million at December 31, 2008 compared to \$9,543 million at December 31, 2007 primarily as a result of the decrease in the period end U.S./Canadian dollar exchange rate. EnCana's 2008 weighted average interest rate on outstanding debt was 5.5 percent compared to 5.6 percent in 2007.

Foreign exchange losses of \$253 million and \$423 million in the fourth quarter and full year of 2008, respectively, are primarily due to the effects of the U.S./Canadian dollar exchange rate on U.S. dollar denominated debt issued from Canada offset by revaluation of the partnership contribution receivable.

The gain on divestitures in 2008 relates primarily to the divestiture of interests in Brazil. The gain on divestitures in 2007 relates primarily to the divestiture of interests in Chad and Australia.

2007 Versus 2006

Administrative expenses increased \$113 million in 2007 compared to 2006 primarily due to higher long-term compensation costs of \$56 million as a result of the change in the EnCana share price. The higher U.S./Canadian dollar exchange rate added an additional \$18 million and the remaining increase was due to increased staff levels, higher salaries, and other related expenses. Administrative expenses in 2007 were \$0.24 per Mcfe compared to \$0.17 per Mcfe in 2006. Fourth quarter administrative expenses increased \$37 million in 2007 compared to 2006 primarily due to higher long-term compensation costs of \$23 million and increased costs of \$13 million due to the higher U.S./Canadian dollar exchange rate.

Net interest expense in 2007 increased \$32 million from 2006 primarily as a result of higher average outstanding debt. EnCana's total long-term debt, including current portion, increased \$2,709 million to \$9,543 million at December 31, 2007 compared to \$6,834 million at December 31, 2006. EnCana's 2007 weighted average interest rate on outstanding debt was 5.6 percent compared to 5.7 percent in 2006.

The foreign exchange gain of \$164 million in 2007 is primarily due to the effects of the U.S./Canadian dollar exchange rate applied to U.S. dollar denominated debt issued from Canada and settlement of foreign denominated intercompany transactions offset by revaluation of the partnership contribution receivable. Fourth quarter 2007 foreign exchange gain of \$233 million is primarily due to the effects of the U.S./Canadian dollar exchange rate on settlement of foreign currency denominated intercompany transactions.

The gain on divestitures in 2007 relates primarily to the divestiture of interests in Chad and assets in Australia. The gain on divestitures in 2006 relates to the divestitures of the Chinook heavy oil discovery offshore Brazil and the Entrega Pipeline.

Summary of Unrealized Mark-to-Market Gains (Losses) from Continuing Operations

(\$ millions)	2008	2007	2006
Revenues			
Natural Gas	\$ 2,475	\$ (1,049)	\$ 1,910
Crude Oil	242	(190)	140
	2,717	(1,239)	2,050
Expenses			
	(12)	(4)	(10)
	2,729	(1,235)	2,060
Income Tax Expense (Recovery)	911	(424)	703
Unrealized Mark-to-Market Gains (Losses), after-tax	\$ 1,818	\$ (811)	\$ 1,357

Commodity price volatility impacts net earnings. As a means of managing this commodity price volatility, EnCana enters into various financial instrument agreements. The financial instrument agreements were recorded at the date of the financial statements based on mark-to-market accounting. Changes in the mark-to-market gains or losses reflected in corporate revenues are the result of volatility between periods in the forward curve commodity price market and changes in the balance of unsettled contracts. Further information regarding financial instrument agreements can be found in Note 20 to the Consolidated Financial Statements.

INCOME TAX

2008 Versus 2007

The effective tax rate for 2008 was 30.7 percent compared to 19.4 percent in 2007. The 2007 effective tax rate was lower primarily due to a one time Canadian federal corporate legislative change and a reduction in the Canadian federal corporate tax rates.

Current income tax expense was \$987 million in 2008 compared to \$1,554 million in 2007. The decrease is primarily due to the increased benefits from international financing and a U.S. tax legislative change in 2008 that allows an accelerated write-off of certain capital expenditures, offset by a one time tax recovery of \$179 million in 2007 for a Canadian tax legislative change.

Future income tax expense was \$1,646 million in 2008 compared to a recovery of \$617 million in 2007. The increase is primarily due to the provision for tax on unrealized mark-to-market hedging gains and the accelerated write-offs for certain U.S. capital expenditures as well as the reduction of the Canadian federal corporate tax rates in 2007 as noted below.

2007 Versus 2006

The effective tax rate for 2007 was 19.4 percent compared to 27.3 percent in 2006. The 2007 rate reflects the effect of a Canadian federal corporate tax legislative change (\$179 million) and a reduction in the Canadian federal corporate tax rate (\$301 million). The legislative change relates to phase in of the deductibility of Crown royalties, which is now complete and will not recur in the future. The Canadian federal tax rate is to be reduced from 19.5 percent to 15 percent between 2008 and 2012. The 2006 effective rate also reflects the effect of reductions in the Canadian federal and Alberta corporate tax rates (\$457 million).

Cash taxes were \$1,554 million in 2007 compared to \$942 million in 2006. The largest component of the increase of \$612 million is \$519 million of higher U.S. taxes in 2007 offset by the cash tax benefit of the legislative change (\$179 million) referred to above. The increase in U.S. tax is due to the cash flows from U.S. downstream refining operations and increased income from U.S. upstream operations.

Further information regarding EnCana's effective tax rate can be found in Note 10 to the Consolidated Financial Statements. EnCana's effective rate in any year is a function of the relationship between total tax (current and future) and the amount of net earnings before income taxes for the year. The effective tax rate differs from the statutory tax rate as it takes into consideration "permanent differences", adjustment for changes to tax rates and other tax legislation, variation in the estimation of reserves and the estimate to actual differences. Permanent differences are a variety of items, including:

- The non-taxable portion of Canadian capital gains or losses;
- Non-taxable downstream partnership income;
- International financing; and
- Foreign exchange (gains) losses not included in net earnings.

Tax interpretations, regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change. As a result, there are usually some tax matters under review. The Company believes that the provision for taxes is adequate.

NET CAPITAL INVESTMENT

Capital Summary

	2008	2007	2006
Canada			
Canadian Plains	\$ 847	\$ 846	\$ 770
Canadian Foothills	2,299	2,439	2,500
Integrated Oil – Canada	656	451	745
USA	2,615	1,919	2,061
Downstream Refining	478	220	–
Market Optimization	17	6	44
Corporate & Other	168	154	149
Capital Investment	7,080	6,035	6,269
Acquisitions	1,174	2,702	331
Divestitures	(904)	(481)	(689)
Discontinued Operations	–	–	(2,647)
Net Capital Investment	\$ 7,350	\$ 8,256	\$ 3,264

EnCana's Capital Investment for the year ended December 31, 2008 was funded by Cash Flow and debt.

Capital investment during 2008 was primarily focused on continued development of EnCana's North American key resource plays and expansion of the Company's downstream heavy oil processing capacity through its joint venture with ConocoPhillips. Reported capital investment was also influenced by changes in the average U.S./Canadian dollar exchange rate and in the EnCana share price. The net impact of these factors on Capital Investment was a decrease of \$149 million in 2008 compared to 2007.

CANADIAN PLAINS DIVISION CAPITAL INVESTMENT

2008 Versus 2007

Canadian Plains capital investment of \$847 million in 2008 was relatively unchanged primarily due to increased land purchases and facility work offset by lower drilling and completion costs due to fewer wells drilled and lower capitalized costs for long-term incentives. Canadian Plains drilled 1,476 net wells in 2008 compared to 2,264 net wells in 2007, focusing more on deeper integrated wells in 2008.

2007 Versus 2006

Canadian Plains capital investment of \$846 million in 2007 increased \$76 million primarily due to the rise in the average U.S./Canadian dollar exchange rate that increased capital by \$47 million. In addition, the Company drilled a larger number of lower cost wells in the Shallow Gas key resource play. Canadian Plains drilled 2,264 net wells in 2007 compared to 1,634 net wells in 2006.

CANADIAN FOOTHILLS DIVISION CAPITAL INVESTMENT

Canadian Foothills Division includes the Company's Canadian offshore assets.

2008 Versus 2007

Canadian Foothills capital investment of \$2,299 million in 2008 decreased \$140 million primarily due to lower drilling costs as a result of increased focus on well tie-ins, more efficient completion techniques and lower capitalized costs for long-term incentives. Canadian Foothills drilled 1,064 net wells in 2008 compared to 1,539 net wells in 2007.

2007 Versus 2006

Canadian Foothills capital investment of \$2,439 million in 2007 decreased \$61 million primarily due to:

- Drilling and completion costs decreased due to increased efficiencies through the use of fit-for-purpose rigs. In addition, the Company drilled a larger number of lower cost wells in the CBM key resource play. Canadian Foothills drilled 1,539 net wells in 2007 compared to 1,275 net wells in 2006;
- Facility costs decreased mainly due to higher costs in 2006 resulting from the construction of the Steeprock and Kakwa gas plants at Cutbank Ridge and Bighorn, respectively; and
- Offsetting the decreases in capital investment was the rise in the average U.S./Canadian dollar exchange rate which increased Canadian Foothills capital by \$120 million.

USA DIVISION CAPITAL INVESTMENT

2008 Versus 2007

USA capital investment of \$2,615 million in 2008 increased \$696 million primarily due to increased drilling and completion activity in the East Texas, Piceance and Jonah key resource plays, including incremental costs from the Deep Bossier acquisition offset slightly by lower capitalized costs for long-term incentives. The number of net wells drilled in the USA increased to 750 from 644 in 2007.

2007 Versus 2006

USA capital investment decreased \$142 million to \$1,919 million primarily due to lower drilling and completion costs resulting from increased efficiencies through the use of additional fit-for-purpose rigs. EnCana employed an average of 22 fit-for-purpose rigs during 2007 compared to 5 during 2006. The number of net wells drilled in the USA increased slightly to 644 from 639 in 2006.

INTEGRATED OIL DIVISION CAPITAL INVESTMENT

Integrated Oil Division is the combined total of Integrated Oil – Canada and Downstream Refining.

2008 Versus 2007

Integrated Oil Division capital investment of \$1,134 million during 2008 was primarily focused on continued development of the Foster Creek and Christina Lake resource plays and on the CORE project at the Wood River refinery. The \$463 million increase in capital investment in 2008 compared to 2007 was primarily due to:

- Higher facility costs at Foster Creek and Christina Lake and spending related to the Wood River CORE project. Facility expenditures at Foster Creek are expected to increase plant capacity to 120,000 bbls/d (on a 100 percent basis) to accommodate Phases D and E expansions. Christina Lake facility costs are expected to increase plant capacity to 58,000 bbls/d (on a 100 percent basis) to accommodate Phases B and C expansion. In addition, drilling costs were higher mainly due to drilling of 139 stratigraphic test wells in 2008 (2007 – 75 wells) at Foster Creek, Christina Lake, Borealis and Senlac related to the next phases of development. The Wood River CORE project received regulatory approvals in the third quarter of 2008 and is expected to cost about \$1.8 billion, net to EnCana, over the next three years. The expansion is expected to increase crude oil refining capacity by 50,000 bbls/d to 356,000 bbls/d (on a 100 percent basis) and heavy crude oil refining capacity is expected to more than double to 240,000 bbls/d (on a 100 percent basis);

offset partially by:

- Lower capitalized costs for long-term incentives.

2007 Versus 2006

Integrated Oil capital investment during 2007 was primarily focused on continued development of the Foster Creek and Christina Lake resource plays and on capacity maintenance and heavy oil expansion projects at the Wood River and Borger refineries.

MARKET OPTIMIZATION CAPITAL INVESTMENT

Market Optimization capital investment in 2008 and 2007 was focused on developing infrastructure for optimization activities and maintaining power generation facilities. Expenditures in 2006 were mostly focused on the completion of construction for the Entrega Pipeline prior to the sale in February 2006.

CORPORATE AND OTHER CAPITAL INVESTMENT

Corporate and Other capital investment in 2008 and 2007 was primarily directed to business information systems, leasehold improvements and office furniture as well as to the Company's International exploration prospects. On February 9, 2007, EnCana announced that it had completed the next phase in the development of The Bow office project with the sale of project assets and entered into a 25 year lease agreement with a third-party developer. Cost-of-design changes to the building requested by EnCana and leasehold improvements are the responsibility of the Company.

ACQUISITIONS AND DIVESTITURES

Acquisitions in 2008 included land purchases of approximately \$1,010 million in the Haynesville Shale play in Louisiana. Acquisitions in 2007 included the purchase of all of the Deep Bossier natural gas and land interests of privately owned Leor Energy group in East Texas for approximately \$2.55 billion before closing adjustments, increasing EnCana's interest to 100 percent in these lands.

In September 2008, EnCana completed the sale of its interests in Brazil for net proceeds of \$164 million, before closing adjustments, resulting in a gain on sale of \$124 million before-tax (\$99 million after-tax). In addition, during 2008, EnCana also completed the divestiture of mature conventional oil and natural gas assets for proceeds of \$698 million.

EnCana completed the following divestitures in 2007:

- The sale of assets in Australia for \$31 million resulting in a gain on sale of \$30 million before-tax (\$25 million after-tax);
- The sale of certain assets in the Mackenzie Delta and Beaufort Sea for proceeds of \$159 million;
- The sale of its interests in Chad for \$208 million resulting in a gain on sale of \$59 million;
- The sale of The Bow office project assets for approximately \$57 million, largely representing its investment at the date of sale; and
- The sale of other minor properties.

Proceeds from the 2007 divestitures were directed primarily to the purchase of shares under EnCana's NCIB.

Proved Oil and Gas Reserves

Proved Reserves by Country

Constant Prices After Royalties	Natural Gas (billions of cubic feet)			Crude Oil and NGLs ⁽¹⁾ (millions of barrels)		
	2008	2007	2006	2008	2007	2006
As at December 31						
Canada ⁽²⁾	7,847	7,292	7,028	954.0	868.9	1,079.4
United States	5,831	6,008	5,390	51.6	58.3	54.0
Total	13,678	13,300	12,418	1,005.6	927.2	1,133.4

(1) Crude Oil and NGLs include condensate.

(2) Includes Foster Creek/Christina Lake.

Each year, EnCana engages independent qualified reserves evaluators to prepare reports on 100 percent of the Company's oil and natural gas reserves. The Company has a Reserves Committee of independent Board of Directors members, which reviews the qualifications and appointment of the independent qualified reserves evaluators. The Committee also reviews the procedures for providing information to the evaluators. EnCana's disclosure of reserves data is covered by National Instrument 51-101 ("NI 51-101") of the Canadian Securities Administrators as amended by a Decision dated September 29, 2008 permitting the adoption of U.S. reporting standards, including compliance with the practices and procedures of the U.S. Securities and Exchange Commission ("SEC") and U.S. Financial Accounting Standards Board ("FASB") reserves reporting requirements. These standards require that reserves be estimated employing the single day field price of the commodity at the effective date of the valuation – in this case, December 31, 2008.

As of December 31, 2009, the SEC will permit companies to disclose their probable and possible reserves in their SEC filings and determine their oil and gas reserves using an average price based upon the prior 12-month period rather than year-end prices. Further information regarding these new disclosure requirements can be found under the Accounting Policies and Estimates section of this MD&A.

Proved Reserves Reconciliation by Country

Constant Prices After Royalties	Natural Gas (billions of cubic feet)			Crude Oil and NGLs ⁽¹⁾ (millions of barrels)		
	Canada	United States	Total	Canada ⁽²⁾	United States	Total
As at December 31, 2008						
Beginning of year	7,292	6,008	13,300	868.9	58.3	927.2
Revisions and improved recovery	148	(166)	(18)	112.8	(3.6)	109.2
Extensions and discoveries	1,311	655	1,966	17.0	3.8	20.8
Acquisitions	32	7	39	0.2	—	0.2
Divestitures	(129)	(75)	(204)	(0.9)	(2.0)	(2.9)
Production	(807)	(598)	(1,405)	(44.0)	(4.9)	(48.9)
End of year	7,847	5,831	13,678	954.0	51.6	1,005.6

(1) Crude Oil and NGLs include condensate.

(2) Includes Foster Creek/Christina Lake.

NATURAL GAS

EnCana's proved natural gas reserves at December 31, 2008 totaled 13,678 Bcf. Approximately 125 percent of production was replaced by reserves additions during 2008. Extensions and discoveries resulting from successful exploration and development capital programs amounted to 1,966 Bcf. Negative revisions of 18 Bcf were less than 1 percent of natural gas reserves at the beginning of 2008. In Canada, positive revisions of 148 Bcf (or 2 percent of the opening balance) were largely associated with the Bighorn, Shallow Gas and Integrated CBM key resource plays. Downward revisions in the U.S. amounted to 166 Bcf (or 3 percent of the opening balance), mainly due to lower prices in the U.S. Rockies. In total, EnCana's key resource plays accounted for over 70 percent of extensions and discoveries. Deep Panuke accounts for over 15 percent of extensions and discoveries. Divestitures net of acquisitions account for approximately 1 percent of the opening natural gas reserves balance.

CRUDE OIL AND NGLs

EnCana's proved crude oil and NGLs reserves at December 31, 2008 totaled 1,005.6 MMbbls. Approximately 260 percent of production was replaced by reserves additions during 2008. Extensions and discoveries amounted to 20.8 MMbbls, while revisions were positive 109.2 MMbbls (or 12 percent of the opening balance). Foster Creek and Christina Lake on a combined basis accounted for approximately 82 MMbbls or 75 percent of revisions and improved recovery. This was primarily due to lower royalties as a result of lower field prices at December 31, 2008. Over 80 percent of extensions and discoveries were in Canada. Reserves changes due to acquisitions and divestitures during 2008 were not significant.

Discontinued Operations

In keeping with EnCana's North American resource play and refining operations strategy, the Company has made a number of divestitures over the years that are accounted for as discontinued operations. EnCana's 2008 Net Earnings from Discontinued Operations were nil (2007 – \$75 million; 2006 – \$601 million).

MIDSTREAM

The \$75 million gain on discontinuance in 2007 was the result of an expired obligation included in the December 2005 sale of the Company's Midstream NGLs processing operations. The obligation provided potential market price support and was accrued for in 2005.

During 2006, EnCana completed, in two separate transactions with a single purchaser, the sale of its natural gas storage operations in Canada and the United States. Total proceeds received were approximately \$1.5 billion and an after-tax gain on sale of \$829 million was recorded.

ECUADOR

On February 28, 2006, EnCana completed the sale of its Ecuador operations for proceeds of \$1.4 billion before indemnifications. A loss of \$279 million, including the impact of indemnifications, was recorded.

EnCana agreed to indemnify the purchaser of its Ecuador interests against losses that may arise in certain circumstances, which are defined in the share sale agreements. The obligation to indemnify will arise should losses exceed amounts specified in the sale agreements and is limited to maximum amounts, which are set forth in the share sale agreements.

During the second quarter of 2006, the Government of Ecuador seized the Block 15 assets, in relation to which EnCana previously held a 40 percent economic interest, from the operator, which is an event requiring indemnification under the terms of EnCana's sale agreement with the purchaser. The purchaser requested payment and EnCana paid the maximum amount calculated in accordance with the terms of the agreements, approximately \$265 million. EnCana does not expect that any further significant indemnification payments relating to any other business matters addressed in the share sale agreements will be required to be made to the purchaser.

Amounts recorded as DD&A in 2006 represent provisions that were recorded against the net book value of the Ecuador operations to recognize Management's best estimate of the difference between the selling price and the underlying accounting value of the related investments, as required by Canadian GAAP.

Liquidity and Capital Resources

(\$ millions)	2008	2007	2006
Net cash from (used in)			
Operating activities	\$ 8,855	\$ 8,429	\$ 7,973
Investing activities	(7,553)	(8,175)	(3,382)
Financing activities	(1,439)	(119)	(4,294)
Foreign exchange gain (loss) on cash and cash equivalents held in foreign currency	(33)	16	-
Increase (decrease) in cash and cash equivalents	\$ (170)	\$ 151	\$ 297

OPERATING ACTIVITIES

Net cash from operating activities in 2008 increased \$426 million compared to 2007. Cash Flow was \$9,386 million in 2008 compared to \$8,453 million in 2007. Reasons for this change are discussed under the Cash Flow section of this MD&A. Cash from operating activities was also impacted by net changes in non-cash working capital and net changes in other assets and liabilities, including decreases in accounts payable and accrued liabilities and income tax payable offset by decreases in accounts receivable and accrued revenues and inventories. Excluding the impact of current risk management assets and liabilities, the Company had a working capital deficit of \$1,067 million at December 31, 2008 compared to \$2,064 million at December 31, 2007. As is typical in the oil and gas industry, there is a timing difference between cash receipts from sales transactions and payments of trade payables, which often results in a working capital deficit. EnCana anticipates that it will continue to meet the payment terms of its suppliers.

INVESTING ACTIVITIES

Net cash used for investing activities in 2008 decreased \$622 million compared to 2007. Capital expenditures, including property acquisitions, in 2008 decreased \$483 million compared to 2007 and proceeds from divestitures increased \$423 million compared to 2007. Reasons for this change are discussed under the Net Capital Investment section of this MD&A. Decreases in cash used for investing activities were partially offset by net changes in investments and other.

FINANCING ACTIVITIES

Net issuance of long-term debt in 2008 was \$6 million compared to net issuance of \$2,333 million in 2007. EnCana's total long-term debt, including current portion, was \$9,005 million at December 31, 2008 compared to \$9,543 million at December 31, 2007. The reduction in debt was primarily attributable to the lower period end U.S./Canadian dollar exchange rate.

EnCana maintains a Canadian and a U.S. dollar shelf prospectus and two committed bank credit facilities.

As at December 31, 2008, EnCana had available unused capacity under shelf prospectuses, the availability of which is dependent on market conditions, for up to \$5.0 billion.

On March 11, 2008, EnCana filed a shelf prospectus whereby it may issue from time to time up to \$4.0 billion, or the equivalent in foreign currencies, of debt securities in the United States. At December 31, 2008, \$4.0 billion of the shelf prospectus remains unutilized, the availability of which is dependent upon market conditions. The shelf prospectus replaces EnCana's \$2.0 billion shelf prospectus, which was fully utilized, and EnCana Holdings Finance Corp.'s \$2.0 billion shelf prospectus, which expired on July 9, 2008.

EnCana has in place a shelf prospectus whereby it may issue from time to time up to C\$2.0 billion, or the equivalent in foreign currencies, of debt securities in Canada. The shelf prospectus was renewed in 2007 and expires in June 2009. The Company plans to renew the shelf prospectus upon expiry.

On January 18, 2008, EnCana completed a public offering in Canada of senior unsecured medium term notes in the aggregate principal amount of C\$750 million. The notes have a coupon rate of 5.80 percent and mature on January 18, 2018. The net proceeds of the offering were used to repay a portion of EnCana's existing bank and commercial paper indebtedness.

As at December 31, 2008, EnCana had available unused committed bank credit facilities in the amount of \$2.6 billion. EnCana has in place a revolving bank credit facility for C\$4.5 billion that remains committed through October 28, 2012. One of EnCana's U.S. subsidiaries has in place a revolving bank credit facility for \$600 million, of which \$565 million is accessible, that remains committed through February 28, 2013. One of the lenders under the \$600 million revolving credit facility, Lehman Brothers Bank, FSB, ceased funding its \$35 million commitment as a result of the bankruptcy filing made by its affiliate, Lehman Brothers Holdings Inc., on September 15, 2008.

EnCana is currently in compliance with and anticipates that it will continue to be in compliance with all financial covenants under its credit facility agreements.

EnCana maintains investment grade credit ratings on its senior unsecured debt. On May 12, 2008, following the announcement of the proposed Arrangement, Standard & Poor's Ratings Service assigned a rating of A- and placed the Company on "CreditWatch Negative", DBRS Limited assigned a rating of A(low) and placed the Company "Under Review with Developing Implications" and Moody's Investors Services assigned a rating of Baa2 and changed the outlook to "Stable" from "Positive".

EnCana has obtained regulatory approval under Canadian securities laws to purchase Common Shares under a NCIB. During 2008, EnCana purchased 4.8 million of its Common Shares for total consideration of approximately \$326 million compared with 38.9 million Common Shares for total consideration of approximately \$2,025 million in 2007. As of December 31, 2008, the number of Common Shares that EnCana will be permitted to purchase in 2009 under the current NCIB is approximately 75.0 million. As a result of the proposed Arrangement, EnCana has suspended the purchase of Common Shares. Shareholders may obtain a copy of the Company's Notice of Intention to make a Normal Course Issuer Bid by contacting investor.relations@encana.com or at www.sedar.com.

EnCana pays quarterly dividends to shareholders at the discretion of the Board of Directors. EnCana doubled its quarterly dividend to 40 cents per share in 2008 and payments for 2008 totaled \$1,199 million compared to \$603 million in 2007. These dividends were funded by Cash Flow.

Financial Metrics

	2008	2007	2006
Debt to Capitalization ⁽¹⁾	28%	32%	28%
Debt to Adjusted EBITDA ⁽²⁾	0.7x	1.1x	0.7x

(1) Capitalization is a non-GAAP measure defined as Long-Term Debt including current portion plus Shareholders' Equity.

(2) Trailing 12-month Adjusted EBITDA is a non-GAAP measure defined as Net Earnings from Continuing Operations before gains or losses on divestitures, income taxes, foreign exchange gains or losses, interest net, accretion of asset retirement obligation, and depreciation and amortization.

Debt to Capitalization and Debt to Adjusted EBITDA are two ratios Management uses to steward the Company's overall debt position as measures of the Company's overall financial strength.

To provide a more conservative measure of liquidity, the Company has changed its calculation of these metrics as follows: Net Debt to Capitalization has been changed to Debt to Capitalization and Net Debt to Adjusted EBITDA has been changed to Debt to Adjusted EBITDA. Debt is defined as the current and long-term portions of Long-Term Debt. Previously, Net Debt was defined as Long-Term Debt plus Current Liabilities less Current Assets. The Company believes this presentation is more comparable between periods by excluding the impact of unrealized mark-to-market accounting gains and losses on working capital.

At December 31, 2008, EnCana's Debt to Capitalization ratio was 28 percent (December 31, 2007 – 32 percent). Without giving effect to the change in calculation as described above, EnCana's Net Debt to Capitalization ratio would have been 23 percent at December 31, 2008 (December 31, 2007 – 34 percent). EnCana targets a Debt to Capitalization ratio of between 30 to 40 percent and a Debt to Adjusted EBITDA of 1.0 to 2.0 times to steward the Company's overall debt position.

FREE CASH FLOW

EnCana's 2008 Free Cash Flow of \$2,306 million was slightly lower compared to 2007. Reasons for the increase in total Cash Flow and capital investment are discussed under the Cash Flow and Net Capital Investment sections of this MD&A.

(\$ millions)	2008	2007	2006
Cash Flow ⁽¹⁾	\$ 9,386	\$ 8,453	\$ 7,161
Capital Investment	7,080	6,035	6,269
Free Cash Flow ⁽²⁾	\$ 2,306	\$ 2,418	\$ 892

(1) Cash Flow is a non-GAAP measure and is defined under the Cash Flow section of this MD&A.

(2) Free Cash Flow is a non-GAAP measure that EnCana defines as Cash Flow in excess of Capital Investment, excluding net acquisitions and divestitures, and is used by Management to determine the funds available for other investing and/or financing activities.

As part of ongoing efforts to maintain financial resilience and flexibility, EnCana has taken steps to reduce pricing risk through a commodity price hedging program. Further information regarding this program can be found under the Risk Management section of this MD&A.

Outstanding Share Data

(millions)	2008	2007	2006
Common Shares outstanding, beginning of year	750.2	777.9	854.9
Common Shares issued under option plans	3.0	8.3	8.6
Common Shares purchased	(2.8)	(36.0)	(85.6)
Common Shares outstanding, end of year	750.4	750.2	777.9
Weighted average Common Shares outstanding – diluted	751.8	764.6	836.5

The Company is authorized to issue an unlimited number of Common Shares, an unlimited number of First Preferred Shares and an unlimited number of Second Preferred Shares. There were no Preferred Shares outstanding as at December 31, 2008, 2007 and 2006.

Employees have been granted options to purchase Common Shares under various plans. At December 31, 2008, approximately 0.5 million options without Tandem Share Appreciation Rights ("TSARs") attached were outstanding, all of which are exercisable.

Stock options granted after December 31, 2003 have an associated TSAR attached, which gives employees the right to elect to receive a cash payment equal to the excess of the market price of EnCana's Common Shares over the exercise price of their stock option in exchange for surrendering their stock option. The exercise of a TSAR, for a cash payment, does not result in the issuance of any additional EnCana Common Shares, so has no dilutive effect. Historically, virtually all employees holding options with TSARs attached deciding to realize the value of their options have exercised their TSARs to receive a cash payment. At December 31, 2008, approximately 19.4 million options with TSARs attached were outstanding, of which 8.5 million are exercisable.

In 2007 and 2008, EnCana also granted Performance TSARs, which vest and expire under the same terms and service conditions as TSARs and are also subject to EnCana attaining prescribed performance relative to pre-determined key measures. Performance TSARs that do not vest when eligible are forfeited. At December 31, 2008, approximately 13.0 million Performance TSARs were outstanding, of which 1.5 million are exercisable.

During the first quarter of 2008, vesting provisions for the Performance Share Units ("PSUs") granted in 2005 were met and 2.0 million shares were distributed from the EnCana Employee Benefit Plan Trust. Additional information on these incentives is contained in Note 19 of the Consolidated Financial Statements.

In 2008, EnCana granted Share Appreciation Rights ("SARs") and Performance SARs to certain employees, which entitle the employee to receive a cash payment equal to the excess of the market price of EnCana's Common Shares at the time of exercise over the grant price. SARs are exercisable at 30 percent of the number granted after one year, an additional 30 percent of the number granted after two years and are fully exercisable after three years and expire five years after the grant date. Performance SARs vest and expire under the same terms and service conditions as SARs and are also subject to EnCana attaining prescribed performance relative to pre-determined key measures. Performance SARs that do not vest when eligible are forfeited. At December 31, 2008, approximately 2.9 million SARs and Performance SARs were outstanding, of which none are exercisable.

Contractual Obligations, Commitments and Contingencies

Contractual Obligations and Commitments ⁽¹⁾

(\$ millions)	Expected Payment Date					Total
	2009	2010 to 2011	2012 to 2013	2014+		
Long-Term Debt ⁽²⁾	\$ 250	\$ 700	\$ 2,565	\$ 5,512	\$ 9,027	
Partnership Contribution Payable ⁽³⁾	306	670	754	1,433	3,163	
Asset Retirement Obligation	87	64	68	6,350	6,569	
Pipeline Transportation	469	970	977	2,533	4,949	
Purchase of Goods and Services	1,061	756	393	534	2,744	
Product Purchases	23	43	36	43	145	
Operating Leases ⁽⁴⁾	70	191	334	2,678	3,273	
Capital Commitments	5	106	–	38	149	
Other Long-Term Commitments	15	16	1	–	32	
Total	\$ 2,286	\$ 3,516	\$ 5,128	\$ 19,121	\$ 30,051	
Product Sales	\$ 38	\$ 80	\$ 89	\$ 149	\$ 356	
Partnership Contribution Receivable ⁽³⁾	313	677	752	1,405	3,147	

- (1) In addition, the Company has made commitments related to its risk management program. See Note 20 to the Consolidated Financial Statements. The Company has an obligation to fund its defined benefit pension and Other Post-Employment Benefit plans as disclosed in Note 19 to the Consolidated Financial Statements.
- (2) Principal component only. See Note 15 to the Consolidated Financial Statements.
- (3) Principal component only. See Note 11 to the Consolidated Financial Statements.
- (4) Related to office space.

EnCana has entered into various commitments primarily related to debt, demand charges on firm transportation agreements, capital commitments and marketing agreements.

Included in EnCana's total long-term debt obligations of \$9,027 million at December 31, 2008 are \$1,657 million in obligations related to Bankers' Acceptances, Commercial Paper and LIBOR loans. These amounts are fully supported and Management expects that they will continue to be supported by revolving credit and term loan facilities that have no repayment requirements within the next year. The revolving credit and term loan facilities are fully revolving for the periods disclosed in the Liquidity and Capital Resources section of this MD&A. Based on the current maturity dates of the credit facilities, these amounts are included in cash outflows for the period disclosed as 4 to 5 years as described in Note 20 to the Consolidated Financial Statements. Further details regarding EnCana's long-term debt are described in Note 15 to the Consolidated Financial Statements.

The Company expects its 2009 commitments to be funded from Cash Flow.

As at December 31, 2008, EnCana remained a party to long-term, fixed price, physical contracts with a current delivery of approximately 33 MMcf/d, with varying terms and volumes through 2017. The total volume to be delivered within the terms of these contracts is 97 Bcf at a weighted average price of \$3.66 per Mcf.

LEASES

In the normal course of business, EnCana leases office space for personnel who support field operations and for corporate purposes.

DEEP PANUKE

In October 2007, EnCana received regulatory approval from the Canada-Nova Scotia Offshore Petroleum Board to develop the Deep Panuke natural gas project located about 175 kilometres offshore Nova Scotia. Expected to start production in 2010, the approximately \$760 million project is expected to deliver between 200 MMcf/d and 300 MMcf/d.

On January 4, 2008, EnCana signed the contract for the design and construction of the Production Field Centre ("PFC") for the Deep Panuke project. The agreement is for Single Buoy Moorings to construct a production facility that EnCana will lease upon delivery, expected in late 2010. EnCana also has the option to purchase the facility. EnCana has determined that it has substantially all the construction period risk and consequently is reporting the PFC as an asset under construction during the construction period.

THE BOW

On February 9, 2007, EnCana announced that it had completed the next phase in the development of The Bow office project with the sale of project assets and has entered into a 25 year lease agreement with a third-party developer. Cost of design changes to the building requested by EnCana and leasehold improvements will be the responsibility of the Company. As such, The Bow is reported as an asset under construction during the construction period.

VARIABLE INTEREST ENTITIES ("VIEs")

On September 25, 2008, EnCana acquired certain land and property in Louisiana for approximately \$101 million before closing adjustments. The purchase was facilitated by an unrelated party, Brown Haynesville Leasehold LLC ("Brown Haynesville"), which holds the majority of the assets in trust for the Company in anticipation of a qualifying like kind exchange for U.S. tax purposes.

On July 23, 2008, EnCana acquired certain land and mineral interests in Louisiana for approximately \$457 million before closing adjustments. The purchase was facilitated by an unrelated party, Brown Southwest Minerals LLC ("Brown Southwest"), which holds the majority of the assets in trust for the Company in anticipation of a qualifying like kind exchange for U.S. tax purposes. On November 12, 2008, an unrelated party exercised an option to purchase certain interests as part of the above acquisition for \$157 million, reducing the qualifying like kind exchange to approximately \$300 million.

Pursuant to the agreements with Brown Haynesville and Brown Southwest, EnCana operates the properties, receives all the revenue and pays all of the expenses associated with the properties. The arrangements with Brown Haynesville and Brown Southwest will be completed on March 24, 2009 and January 19, 2009, respectively, and the assets will be transferred to EnCana at that time. EnCana has determined that each relationship with Brown Haynesville and Brown Southwest represents an interest in a VIE and that EnCana is the primary beneficiary of the VIE. EnCana has consolidated Brown Haynesville and Brown Southwest from the dates of acquisition.

On November 20, 2007, EnCana acquired certain natural gas and land interests in Texas for approximately \$2.55 billion before closing adjustments. The purchase was facilitated by an unrelated party, Brown Kilgore Properties LLC ("Brown Kilgore"), which held the majority of the assets in trust for the Company in anticipation of a qualifying like kind exchange for U.S. tax purposes. The relationship with Brown Kilgore represented an interest in a VIE from November 20, 2007 to May 18, 2008. During this period, EnCana was the primary beneficiary of the VIE and consolidated Brown Kilgore. On May 18, 2008, when the arrangement with Brown Kilgore was completed, the assets were transferred to EnCana.

LEGAL PROCEEDINGS

EnCana is involved in various legal claims associated with the normal course of operations and believes it has made adequate provision for such legal claims.

DISCONTINUED MERCHANT ENERGY OPERATIONS

During the period between 2003 and 2005, EnCana and its indirect wholly owned U.S. marketing subsidiary, WD Energy Services Inc. ("WD"), along with other energy companies, were named as defendants in several lawsuits, some of which were class action lawsuits, relating to sales of natural gas from 1999 to 2002. The lawsuits allege that the defendants engaged in a conspiracy with unnamed competitors in the natural gas markets in California in violation of U.S. and California anti-trust and unfair competition laws.

Without admitting any liability in the lawsuits, WD agreed to settle all of the class action lawsuits in both state and federal court for payment of \$20.5 million and \$2.4 million, respectively. Also, as previously disclosed, without admitting any liability whatsoever, WD concluded settlements with the U.S. Commodity Futures Trading Commission ("CFTC") for \$20 million and of a previously disclosed consolidated class action lawsuit in the United States District Court in New York for \$8.2 million. Also, without admitting any liability whatsoever, WD concluded settlements with a group of individual plaintiffs for \$23 million.

The remaining lawsuit was commenced by E. & J. Gallo Winery ("Gallo"). The Gallo lawsuit claims damages in excess of \$30 million. California law allows for the possibility that the amount of damages assessed could be tripled.

The Company and WD intend to vigorously defend against this outstanding claim; however, the Company cannot predict the outcome of these proceedings or any future proceedings against the Company, whether these proceedings would lead to monetary damages which could have a material adverse effect on the Company's financial position, or whether there will be other proceedings arising out of these allegations.

Accounting Policies and Estimates

NEW ACCOUNTING STANDARDS ADOPTED

The Company adopted the Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3031 "Inventories", Section 3863 "Financial Instruments – Presentation", Section 3862 "Financial Instruments – Disclosures" and Section 1535 "Capital Disclosures" on January 1, 2008. The adoption of these standards has had no material impact on the Company's Net Earnings or Cash Flows. Additional information on the effects of the implementation of the new standards can be found in Note 2 to the Consolidated Financial Statements.

RECENT ACCOUNTING PRONOUNCEMENTS

As of January 1, 2009, EnCana will be required to adopt the CICA Handbook Section 3064, "Goodwill and Intangible Assets", which will replace the existing Goodwill and Intangible Assets standard. The new standard revises the requirement for recognition, measurement, presentation and disclosure of intangible assets. The adoption of this standard should not have a material impact on EnCana's Consolidated Financial Statements.

Oil and Gas Reserves

As previously described, EnCana currently follows the U.S. reporting standards for disclosure of reserves data. As of December 31, 2009, EnCana will be required to prospectively adopt the new reserves disclosure requirements announced by the U.S. SEC on December 29, 2008. The new rules include provisions that permit the use of new technologies to establish proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes. The new rules permit companies to disclose probable and possible reserves in addition to proved reserves. In addition, the new rules require companies to report the independence and qualifications of a reserves preparer or auditor and report oil and gas reserves using an average price based upon the prior 12-month period rather than year-end prices.

The new rules will affect the determination of proved reserves and therefore will impact the Company's oil and gas information disclosed in accordance with Statement of Financial Accounting Standard ("SFAS") 69, including the net proved reserves and the standardized measure of discounted future net cash flows. As well, the new rules will affect the reserves estimate used in the calculation of DD&A and the ceiling test for U.S. GAAP purposes. The Company is assessing the impact these new rules will have on its Consolidated Financial Statements and oil and gas disclosures.

International Financial Reporting Standards ("IFRS")

In February 2008, the CICA's Accounting Standards Board confirmed that IFRS will replace Canadian GAAP in 2011 for profit-oriented Canadian publicly accountable enterprises. EnCana will be required to report its results in accordance with IFRS beginning in 2011. The Company has developed a changeover plan to complete the transition to IFRS by January 1, 2011, including the preparation of required comparative information.

The key elements of EnCana's changeover plan include:

- determine appropriate changes to accounting policies and required amendments to financial disclosures;
- identify and implement changes in associated processes and information systems;
- comply with internal control requirements;
- communicate collateral impacts to internal business groups; and
- educate and train internal and external stakeholders.

The Company is currently analyzing accounting policy alternatives and identifying implementation options for the corresponding process changes. EnCana will update its IFRS changeover plan to reflect new and amended accounting standards issued by the International Accounting Standards Board. As IFRS is expected to change prior to 2011, the impact of IFRS on the Company's Consolidated Financial Statements is not reasonably determinable at this time.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Management is required to make judgments, assumptions and estimates in the application of generally accepted accounting principles that have a significant impact on the financial results of the Company. A summary of EnCana's significant accounting policies can be found in Note 1 to the Consolidated Financial Statements. The following discussion outlines the accounting policies and practices involving the use of estimates that are critical to determining EnCana's financial results.

Full Cost Accounting

EnCana follows the CICA guideline on full cost accounting in the oil and gas industry to account for oil and gas properties. Under this method, all costs, including internal costs and asset retirement costs, directly associated with the acquisition of, exploration for, and the development of natural gas and crude oil reserves, are capitalized on a country-by-country cost centre basis and costs associated with production are expensed. The capitalized costs, including estimated future development costs, are depreciated, depleted and amortized using the unit-of-production method based on estimated proved reserves. Reserves estimates can have a significant impact on earnings, as they are a key component in the calculation of DD&A. A downward revision in reserves estimate could result in a higher DD&A charge to earnings. In addition, if net capitalized costs are determined to be in excess of the calculated ceiling, which is based largely on reserves estimates (see asset impairment discussion below), the excess must be written off as an expense charged against earnings. In the event of a property divestiture, proceeds are normally deducted from the full cost pool without recognition of a gain or loss unless there is a change in the DD&A rate of 20 percent or greater.

Oil and Gas Reserves

All of EnCana's oil and gas reserves and resources are evaluated and reported on by independent qualified reserves evaluators. The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, estimated commodity price forecasts and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. Reserves estimates can be revised upward or downward based on the results of future drilling, testing, production levels and economics of recovery based on cash flow forecasts. Contingent resources are not classified as reserves due to the absence of a commercial development plan that includes a firm intent to develop within a reasonable time frame and, in some cases, due to higher uncertainty as a result of lower core-hole drilling density. Estimated recovery for leases assigned contingent resources considers detailed reservoir and pilot studies, demonstrated commercial success of analogous commercial projects and drilling density.

Asset Impairments

Under full cost accounting, a ceiling test is performed to ensure that unamortized capitalized costs in each cost centre do not exceed their fair value. An impairment loss is recognized in net earnings when the carrying amount of a cost centre is not recoverable and the carrying amount of the cost centre exceeds its fair value. The carrying amount of the cost centre is not recoverable if the carrying amount exceeds the sum of the undiscounted cash flows from proved reserves. If the sum of the cash flows is less than the carrying amount, the impairment loss is limited to an amount by which the carrying amount exceeds the sum of:

- i) the fair value of proved and probable reserves; and
- ii) the costs of unproved properties that have been subject to a separate impairment test.

An impairment loss is recognized on refining property, plant and equipment when the carrying amount is not recoverable and exceeds its fair value. The carrying amount is not recoverable if the carrying amount exceeds the sum of the undiscounted cash flows from expected use and eventual disposition. If the carrying amount is not recoverable, an impairment loss is measured as the amount by which the refinery asset exceeds the discounted future cash flows from the refinery asset. EnCana has assessed its property, plant and equipment for impairment as at December 31, 2008 and has determined that no write-down is required under Canadian GAAP.

Asset Retirement Obligations

The fair value of estimated asset retirement obligations is recognized in the Consolidated Balance Sheet when incurred and a reasonable estimate of fair value can be made. Asset retirement obligations are legal obligations associated with the requirement to retire tangible long-lived assets such as producing well sites, offshore production platforms, natural gas processing plants and refining facilities. The asset retirement cost, equal to the initially estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long-lived asset. Changes in the estimated obligation resulting from revisions to estimated timing or amount of undiscounted cash flows are recognized as a change in the asset retirement obligation and the related asset retirement cost. Increases in the asset retirement obligation resulting from the passage of time are recorded as accretion of asset retirement obligation in the Consolidated Statement of Earnings. Amounts recorded for asset retirement obligations are based on estimates of reserves and on retirement costs, which will not be incurred for several years. Actual expenditures incurred are charged against the accumulated obligation.

Goodwill

Goodwill, which represents the excess of purchase price over fair value of net assets acquired, is assessed by EnCana for impairment at least annually. Goodwill and all other assets and liabilities have been allocated to the country cost centre level, referred to as reporting units. To assess impairment, the fair value of each reporting unit is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, then a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill and comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of goodwill over the implied fair value of goodwill is the impairment amount. EnCana has assessed its goodwill for impairment as at December 31, 2008 and has determined that no write-down is required.

Income Taxes

EnCana follows the liability method of accounting for income taxes. Under this method, future income taxes are estimated and recorded for the effect of any difference between the accounting and income tax basis of an asset or liability, using the substantively enacted income tax rates. Accumulated future income tax balances are adjusted to reflect changes in income tax rates that are substantively enacted with the adjustment being recognized in net earnings in the period that the change occurs.

Tax interpretations, regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change. As such, income taxes are subject to measurement uncertainty.

Derivative Financial Instruments

Derivative financial instruments are used by EnCana to manage its exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. The Company's policy is to not use derivative financial instruments for speculative purposes.

The Company enters into financial transactions to help reduce its exposure to price fluctuations with respect to commodity purchase and sale transactions to achieve targeted investment returns and growth objectives, while maintaining prescribed financial metrics. These transactions generally are swaps, collars, or options and are generally entered into with major financial institutions or commodities trading institutions.

EnCana may also use derivative financial instruments, such as interest rate swap agreements, to manage the fixed and floating interest rate mix of its total debt portfolio and related overall cost of borrowing. The interest rate swap agreements involve the periodic exchange of payments, without the exchange of the normal principal amount upon which the payments are based, and are recorded as an adjustment of interest expense on the hedged debt instrument.

EnCana may enter into hedges of its foreign currency exposures on foreign currency denominated long-term debt by entering into offsetting forward exchange contracts. Foreign exchange translation gains and losses on these instruments are accrued under other current, or non-current, assets or liabilities on the balance sheet and recognized in foreign exchange in the period to which they relate, offsetting the respective translation losses and gains recognized on the underlying foreign currency long-term debt. Premiums or discounts on these forward instruments are amortized as an adjustment of interest expense over the term of the contract.

EnCana also may purchase foreign exchange forward contracts to hedge anticipated sales to customers in the United States. Foreign exchange translation gains and losses on these instruments are recognized as an adjustment of the revenues when the sale is recorded.

Derivative instruments that do not qualify as hedges, or are not designated as hedges, are recorded using the mark-to-market method of accounting whereby instruments are recorded in the Consolidated Balance Sheet as either an asset or liability with changes in fair value recognized in net earnings. Realized gains or losses from the Company's financial derivatives related to natural gas and crude oil prices are recognized in natural gas and crude oil revenues as the related sales occur. Unrealized gains and losses are recognized in revenues at the end of each respective reporting period. The estimate of fair value of all derivative instruments is based on quoted market prices or, in their absence, third-party market indications and forecasts. The estimated fair value of financial assets and liabilities, by their very nature, is subject to measurement uncertainty.

In 2006, 2007, and 2008, the Company elected not to designate any of its price risk management activities as accounting hedges and, accordingly, accounted for all derivatives using the mark-to-market accounting method.

Pensions and Other Post-employment Benefits

EnCana accrues for its obligations under its employee benefit plans and the related costs, net of plan assets.

The cost of pensions and other post-employment benefits is actuarially determined using the projected benefit method based on length of service, and reflects Management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected future health care costs. The expected return on plan assets is based on the fair value of those assets. The accrued benefit obligation is discounted using the market interest rate on high quality corporate debt instruments as at the measurement date.

Pension expense for the defined benefit pension plan includes the cost of pension benefits earned during the current year, the interest cost on pension obligations, the expected return on pension plan assets, the amortization of the net transitional obligation, the amortization of adjustments arising from pension plan amendments and the amortization of the excess of the net actuarial gain or loss over 10 percent of the greater of the benefit obligation and the fair value of plan assets. The amortization period covers the expected average remaining service lives of employees covered by the plans. EnCana's defined benefit pension plan was \$30 million under funded at December 31, 2008. Funding requirements will be determined after completion of the December 31, 2008 actuarial evaluation in the first quarter of 2009 and are not expected to be material.

Pension expense for the defined contribution pension plans is recorded as the benefits are earned by the employees covered by the plan.

Further details are disclosed in Note 19 to the Consolidated Financial Statements.

Performance TSARs, Performance SARs and PSUs

These plans provide for a range of payouts, based on key predetermined performance measures or EnCana's performance relative to certain peers. EnCana expenses the cost of these plans based on expected payouts. However, the amounts to be paid, if any, may vary from the current estimate. Further details on these plans are disclosed in Note 19 to the Consolidated Financial Statements.

Risk Management

EnCana's business, prospects, financial condition, results of operation and cash flows, and in some cases its reputation, are impacted by risks that are categorized as follows:

- financial risks including market risks (such as commodity price, foreign exchange and interest rates), credit and liquidity;
- operational risks including capital, operating and reserves replacement risks; and
- safety, environmental and regulatory risks.

EnCana is committed to identifying and managing these risks in the near-term as well as on a strategic and longer term basis at all levels in the organization in accordance with the Company's Board of Directors' approved Corporate Risk Management policy and EnCana's risk management programs.

Issues affecting, or with the potential to affect, EnCana's reputation are generally of a strategic nature or emerging issues that can be identified early and then managed, but occasionally include unforeseen issues that arise unexpectedly and must be managed on an urgent basis. EnCana takes a proactive approach to the identification and management of issues that affect the Company's reputation and has established consistent and clear policies, procedures, guidelines and responsibilities for identifying and managing these issues.

FINANCIAL RISKS

EnCana defines financial risks as the risk of loss or lost opportunity resulting from financial management and market conditions that could have a positive or negative impact on EnCana's business.

The current global credit crisis and recession is impacting EnCana's business. EnCana has a strong financial position and continues to implement its business model, which focuses on developing low-risk and low-cost long-life resource plays, which allows the Company to respond well to the current market uncertainty. Management has been adjusting operational and financial risk strategies to proactively respond to the difficult economic conditions and to mitigate or reduce risk. The prudent and conservative capital budget for 2009 continues to be monitored and it contains the flexibility to allow spending to be reduced or increased as commodity prices and forecasts are revised, including the impact of changes on EnCana's longer term plans. Cost containment and reduction strategies are in place to ensure all aspects of the Company's controllable costs are efficiently managed. Counterparty and credit risks are closely monitored as are the programs to ensure EnCana's ability to access cost effective credit is maintained and that sufficient cash resources are in place to fund capital expenditures and fund dividend payments. Further insight into these risks and strategies is summarized below.

EnCana partially mitigates its exposure to financial risks through the use of various financial instruments and physical contracts. The use of derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors.

EnCana has in place policies and procedures with respect to the required documentation and approvals for the use of derivative financial instruments and specifically ties their use, in the case of commodities, to the mitigation of price risk to achieve targeted investment returns and growth objectives, while maintaining prescribed financial metrics.

With respect to transactions involving proprietary production or assets, the financial instruments generally used by EnCana are swaps or options, which are entered into with major financial institutions, integrated energy companies or commodities trading institutions.

Further information, including the details of EnCana's positions for these financial instruments as of December 31, 2008, is disclosed in Note 20 to the Consolidated Financial Statements.

Commodity Price

EnCana defines commodity price risk as the uncertainties and fluctuations of future market prices for commodities. To partially mitigate the natural gas commodity price risk, the Company enters into swaps and puts, which establish NYMEX floor prices. To December 31, 2008, EnCana has hedged about two thirds of its expected gas production from January through October 2009 at an average NYMEX equivalent price of about \$9.13 per Mcf. To help protect against widening natural gas price differentials in various production areas, EnCana has entered into swaps to manage the price differentials between these production areas and various sales points. EnCana has also entered into contracts to purchase and sell natural gas as part of its daily ongoing operations of the Company's proprietary production management. As at December 31, 2008, the Company has not hedged any of its exposure to the WTI NYMEX price or crack spreads for its expected 2009 oil production or refining margins. To manage its electricity consumption costs, EnCana has entered into two derivative contracts for a term of 11 years, commencing January 1, 2007.

Credit

EnCana defines credit risk as the potential for loss if a counterparty in a transaction fails to meet its obligations in accordance with agreed terms. A substantial portion of EnCana's accounts receivable is with customers in the oil and gas industry. This credit exposure is mitigated through the use of Board-approved credit policies governing the Company's credit portfolio and with credit practices that limit transactions according to counterparties' credit quality and transactions that are fully collateralized. All financial derivative agreements are with major financial institutions in Canada and the United States or with counterparties having investment grade credit ratings.

Liquidity

EnCana defines liquidity risk as the risk the Company cannot meet a demand for cash or fund obligations as they come due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price. The Company manages liquidity risk through cash and debt management programs, including maintaining a strong balance sheet and significant unused credit facilities. The Company also has access to a wide range of funding alternatives at competitive rates, including commercial paper, capital market debt and bank loans. EnCana maintains investment grade credit ratings on its senior unsecured debt. The details of these facilities as of December 31, 2008 are disclosed in Note 15 to the Consolidated Financial Statements.

Foreign Exchange

EnCana defines foreign exchange risk as the risk of gains or losses that could result from changes in foreign currency exchange rates. As EnCana operates primarily in North America, fluctuations in the exchange rate between the U.S. and Canadian dollar can have a significant effect on the Company's reported results. As a means of mitigating the exposure to fluctuations in the U.S./Canadian dollar exchange rate, EnCana may enter into foreign exchange contracts, in conjunction with crude oil marketing transactions. Gains or losses on these contracts are recognized when the difference between the average month spot rate and the rate on the date of settlement is determined. All foreign exchange agreements are with major financial institutions in Canada and the United States or with counterparties having investment grade credit ratings. By maintaining U.S. and Canadian operations, EnCana has a natural hedge to some foreign exchange exposure.

EnCana also maintains a mix of both U.S. dollar and Canadian dollar debt, which helps to offset the exposure to the fluctuations in the U.S./Canadian dollar exchange rate. In addition to direct issuance of U.S. dollar denominated debt, the Company may enter into cross currency swaps on a portion of its debt as a means of managing the U.S./Canadian dollar debt mix.

Interest Rates

EnCana defines interest rate risk as the impact of changing interest rates on earnings, cash flows, and valuations. The Company partially mitigates its exposure to interest rate changes by maintaining a mix of both fixed and floating rate debt. EnCana may enter into interest rate swap transactions from time to time as an additional means of managing the fixed/floating rate debt portfolio mix.

OPERATIONAL RISKS

Operational risks are defined as the risk of loss or lost opportunity resulting from operating and capital activities that, by their nature, could have an impact on EnCana's ability to achieve its objectives.

The Company's ability to operate, generate cash flows, complete projects, and value reserves is dependent on financial risks, including commodity prices mentioned above, continued market demand for its products and other risk factors outside of its control, which include: general business and market conditions; economic recessions and financial market turmoil; the ability to secure and maintain cost effective financing for its commitments; environmental and regulatory matters; unexpected cost increases; royalties; taxes; the availability of drilling and other equipment; the ability to access lands; weather; the availability of processing capacity; the availability and proximity of pipeline capacity; the availability of diluents to transport crude oil; technology failures; accidents; the availability of skilled labour; and reservoir quality.

If EnCana fails to acquire or find additional crude oil and natural gas reserves its reserves and production will decline materially from their current levels and, therefore, its cash flows are highly dependent upon successfully exploiting current reserves and acquiring, discovering or developing additional reserves.

To mitigate these risks, as part of the capital approval process, the Company's projects are evaluated on a fully risked basis, including geological risk and engineering risk. In addition, the asset teams undertake a process called Lookback and Learning. In this process, each asset team undertakes a thorough review of its previous capital program to identify key learnings, which often include operational issues that positively and negatively impacted the project's results. Mitigation plans are developed for the operational issues that had a negative impact on results. These mitigation plans are then incorporated into the current year plan for the project. On an annual basis, these Lookback results are analyzed for EnCana's capital program with the results and identified learnings shared across the Company.

A peer review process is used to ensure that capital projects are appropriately risked and that knowledge is shared across the Company. Peer reviews are undertaken primarily for exploration projects and early stage resource plays, although they may occur for any type of project.

When making operating and investing decisions, EnCana's business model allows flexibility in capital allocation to optimize investments focused on project returns, long-term value creation, and risk mitigation. EnCana also mitigates operational risks through a number of other policies, systems and processes as well as by maintaining a comprehensive insurance program.

SAFETY, ENVIRONMENTAL AND REGULATORY

EnCana is engaged in relatively higher risk activities of natural gas exploration and production and integrated in-situ oil development. The Company is committed to safety in its operations and with high regard for the environment and stakeholders, including regulators. These risks are managed by executing policies and standards that are designed to comply with or exceed government regulations and industry standards. In addition, EnCana maintains a system that identifies, assesses and controls safety, security and environmental risk and requires regular reporting to Senior Management and the Board of Directors. The Corporate Responsibility, Environment, Health & Safety Committee of EnCana's Board of Directors provides recommended environmental policies for approval by EnCana's Board of Directors and oversees compliance with government laws and regulations. Monitoring and reporting programs for environmental, health and safety performance in day-to-day operations, as well as inspections and assessments, are designed to provide assurance that environmental and regulatory standards are met. Contingency plans are in place for a timely response to an environmental event and remediation/reclamation strategies are utilized to restore the environment. In addition, security risks are managed through a Security Program designed to protect EnCana's personnel and assets.

EnCana has an Investigations Committee with the mandate to address potential violations of Company policies and practices and an Integrity Hotline that can be used to raise any concerns regarding EnCana's operations, accounting or internal control matters.

EnCana's operations are subject to regulation and intervention by governments that can affect or prohibit the drilling, completion and tie-in of wells, production, the construction or expansion of facilities and the operation and abandonment of fields. Contract rights can be cancelled or expropriated. Changes to government regulation could impact the Company's existing and planned projects as well as impose a cost of compliance.

Regulatory and legal risks are identified by the operating divisions and corporate groups and EnCana's compliance with the required laws and regulations is monitored by EnCana's legal group, which stays abreast of new developments and changes in laws and regulations to ensure that EnCana continues to comply with prescribed laws and regulations. Of note in this regard currently is EnCana's approach to changes in regulations relating to climate change and royalty frameworks as discussed below. To partially mitigate resource access risks, keep abreast of regulatory developments and be a responsible operator, EnCana maintains relationships with key stakeholders and conducts other mitigation initiatives mentioned herein.

Climate Change

A number of federal, provincial and state governments have announced intentions to regulate greenhouse gases ("GHG") and other air pollutants while some jurisdictions have provided details on these regulations. It is anticipated that other jurisdictions will announce emissions reduction plans in the future. As these federal and regional programs are under development, EnCana is unable to predict the total impact of the potential regulations upon its business. Therefore, it is possible that the Company could face increases in operating costs in order to comply with GHG emissions legislation. However, EnCana will continue to work with governments to develop an approach to deal with climate change issues that protects the industry's competitiveness, limits the cost and administrative burden of compliance and supports continued investment in the sector.

The Alberta Government has set targets for GHG emissions reductions. In March 2007, regulations were amended to require facilities that emit more than 100,000 tonnes of GHG emissions per year to reduce their emissions intensity by 12 percent from a regulated baseline starting July 1, 2007. To comply, companies can make operating improvements, purchase carbon offsets or make a C\$15 per tonne contribution to an Alberta Climate Change and Emissions Management Fund. In Alberta, EnCana has four facilities covered under the emissions regulations. The forecast cost of carbon associated with the Alberta regulations is not material to EnCana at this time and is being actively managed.

In British Columbia, effective July 1, 2008, a 'revenue neutral carbon tax' will be applied to virtually all fossil fuels, including diesel, natural gas, coal, propane, and home heating fuel. The tax applies to combustion emissions and to the purchase or use of fossil fuels within the province. The rate starts at C\$10 per tonne of carbon equivalent emissions, rising by C\$5 per tonne a year for the next four years. The forecast cost of carbon associated with the British Columbia regulations is not material to EnCana at this time and is being actively managed.

EnCana intends to continue its activity to reduce its emissions intensity and improve its energy efficiency. The Company's efforts with respect to emissions management are founded on the following key elements:

- significant production weighting in natural gas;
- recognition as an industry leader in CO₂ sequestration;
- focus on energy efficiency and the development of technology to reduce GHG emissions;
- involvement in the creation of industry best practices; and
- industry leading steam to oil ratio, which translates directly into lower emissions intensity.

EnCana's strategy for addressing the implications of emerging carbon regulations is proactive and is composed of three principal elements:

1. **Manage Existing Costs** When regulations are implemented, a cost is placed on EnCana's emissions (or a portion thereof) and while these are not material at this stage, they are being actively managed to ensure compliance. Factors such as effective emissions tracking, attention to fuel consumption, and a focus on minimizing the Company's steam to oil ratio help to support and drive its focus on cost reduction.
2. **Respond to Price Signals** As regulatory regimes for GHGs develop in the jurisdictions where EnCana works, inevitably price signals begin to emerge. The Company has initiated an Energy Efficiency Initiative in an effort to improve the energy efficiency of its operations. The price of potential carbon reductions plays a role in the economics of the projects that are implemented. In response to the anticipated price of carbon, EnCana is also attempting, where appropriate, to realize the associated value of its reduction projects.

3. **Anticipate Future Carbon Constrained Scenarios** EnCana continues to work with governments, academics and industry leaders to develop and respond to emerging GHG regulations. By continuing to stay engaged in the debate on the most appropriate means to regulate these emissions, the Company gains useful knowledge that allows it to explore different strategies for managing its emissions and costs. These scenarios inform EnCana's long range planning and its analyses on the implications of regulatory trends.

EnCana incorporates the potential costs of carbon into future planning. Management and the Board review the impact of a variety of carbon constrained scenarios on its strategy, with a current price range from \$15 to \$65 per tonne of emissions applied to a range of emissions coverage levels. A major benefit of applying a range of carbon prices at the strategic level is that it provides direct guidance to the capital allocation process. EnCana also examines the impact of carbon regulation on its major projects. Although uncertainty remains regarding potential future emissions regulation, EnCana's plan is to continue to assess and evaluate the cost of carbon relative to its investments across a range of scenarios.

EnCana recognizes that there is a cost associated with carbon emissions. EnCana is confident that greenhouse gas regulations and the cost of carbon at various price levels have been adequately accounted for as part of its business planning and scenarios analysis. EnCana believes that the resource play strategy is an effective way to develop the resource, generate shareholder returns and coordinate overall environmental objectives with respect to carbon, air emissions, water and land. EnCana is committed to transparency with its stakeholders and will keep them apprised of how these issues affect operations. Additional detail on EnCana's GHG emissions is available in the Corporate Responsibility Report that is available on the Company's website at www.encana.com.

Alberta's New Royalty Framework ("NRF")

On October 25, 2007, the Alberta Government announced the New Royalty Framework. The NRF established new royalties for conventional oil, natural gas and bitumen that are linked to commodity prices, well production volumes and well depths for gas wells and oil quality for oil wells. These new rates apply to both new and existing conventional oil and gas activities and oil sands projects in Alberta. The changes introduced by the NRF became effective as of January 1, 2009.

The NRF established new price-sensitive and volume-sensitive rates for conventional oil that range from 0 percent to 50 percent with the price sensitivity topping out between C\$68 and C\$116 per barrel dependent on the well productivity, and for natural gas that range from 5 percent to 50 percent with the price sensitivity topping out between C\$9.92 and C\$17.75 per gigajoule. On November 19, 2008, the Alberta Government introduced the Transitional Royalty Program ("TRP"), which allows for a one time option of selecting between transitional rates and the NRF rates on new natural gas or conventional oil wells drilled between 1,000 metres to 3,500 metres in depth. These would apply until January 1, 2014, at which time all wells would be moved to the NRF. In addition, the NRF introduces royalty rates for bitumen that range from 1 percent to 9 percent (before payout) and from 25 percent to 40 percent (after payout) with rate caps at C\$120 WTI per barrel.

The NRF has changed the economics of operating in Alberta and the impact of these changes has been reflected in EnCana's 2009 capital program.

Outlook

During the current challenging economic environment, EnCana is highly focused on the key business objectives of maintaining financial strength, generating significant free cash flow, further optimizing capital investments and continuing to pay a stable dividend to shareholders.

EnCana monitors the risks under its control and has policies in place to mitigate those risks. EnCana is managing commodity price risk through its financial risk management program designed to help ensure financial resilience and flexibility and is closely monitoring interest, credit and counterparty risk. In addition, the Company will continue to monitor expenses and capital programs and maintain flexibility to adjust to changing economic circumstances. EnCana has planned a conservative, prudent and flexible capital program in 2009 that

targets total natural gas and oil production at approximately 2008 levels and advances the Company's multi-year projects. EnCana expects to continue to fund the Foster Creek and Christina Lake expansion projects, Wood River CORE project and other capital projects at the present time. EnCana targets a Debt to Capitalization ratio of between 30 to 40 percent and at December 31, 2008, the Company's Debt to Capitalization ratio was 28 percent.

Natural gas prices are primarily driven by North American supply and demand, with weather being the key factor in the short term. EnCana believes that North American conventional gas supply has peaked and that unconventional resource plays can offset conventional gas production declines over the next few years. Past this period, the industry's ability to continue to grow gas supply is expected to be challenged in North America by land access and regulatory issues.

Volatility in crude oil prices is expected to continue throughout 2009 as a result of market uncertainties over supply and refining, changes in demand due to the overall state of the world economies, OPEC actions and the worldwide credit and liquidity crisis. Canadian crude prices will face added uncertainty due to the risk of refinery disruptions in an already tight United States Midwest market and growing domestic production could result in pipeline constraints out of Western Canada.

The Company expects its 2009 capital investment program to be funded from Cash Flow and debt.

As discussed in EnCana's Business section of this MD&A, the Company announced its plans to split into two highly focused energy companies. Given the uncertainty and volatility in the global financial markets, EnCana is choosing to delay the timing of a shareholder vote until clear signs of stabilization return to the financial markets. EnCana is continuing to prepare documentation and maintain support systems in anticipation of the proposed Arrangement.

EnCana, post-Arrangement, plans to focus on growing natural gas production from its diversified portfolio of existing and emerging unconventional resource plays in North America. Cenovus, post-Arrangement, plans to focus on developing its high quality in-situ oil resources, expanding its downstream heavy oil processing capacity through its joint venture with ConocoPhillips and developing its natural gas, crude oil and NGLs resources in Western Canada.

EnCana's results are affected by external market and risk factors, such as fluctuations in the prices of crude oil and natural gas, movements in foreign currency exchange rates and inflationary pressures on service costs. Additional detail regarding the impact of these factors on EnCana's 2009 results is discussed in the Risk Management section of this MD&A and is also available in the Corporate Guidance on the Company's website at www.encana.com. EnCana updated its Corporate Guidance to reflect the impact on operations of expected conditions for 2009. EnCana's news release dated February 12, 2009 and financial statements are available on www.sedar.com.

Advisory

FORWARD-LOOKING STATEMENTS

In the interest of providing EnCana shareholders and potential investors with information regarding the Company and its subsidiaries, including Management's assessment of EnCana's and its subsidiaries' future plans and operations, certain statements contained in this document constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of the "safe harbour" provisions of applicable securities legislation. Forward-looking statements are typically identified by words such as "anticipate", "believe", "expect", "plan", "intend", "forecast", "target", "project" or similar words suggesting future outcomes or statements regarding an outlook. Forward-looking statements in this document include, but are not limited to, statements with respect to: projections relating to drilling inventories and reserve life index; target risk-adjusted rates of return which may be achieved; resource potential which may be available from the Haynesville Shale and Horn River Shale plays; projections for 2009 production levels, after-tax cash flow and free cash flow; projections relating to expected Rockies basis differential and the impact of the Company's hedging program thereon through 2011; the expected benefits of new horizontal well drilling and fracing technology; projections relating to the adequacy of the Company's provision for taxes; the potential impact of the Alberta Royalty Framework; projections with respect to growth of natural gas production from unconventional resource plays and in-situ oil resources including with respect to the Foster Creek

and Christina Lake projects, the CORE project and planned expansions of the Company's downstream heavy oil processing capacity and the capital costs and expected timing of the same; the projected impact of land access and regulatory issues; projections relating to the volatility of crude oil prices in 2009 and beyond and the reasons therefor; the Company's projected capital investment levels for 2009, the flexibility of capital spending plans and the source of funding therefor; the effect of the Company's risk management program, including the impact of derivative financial instruments; the Company's defence of lawsuits; the impact of the changes and proposed changes in laws and regulations, including greenhouse gas, carbon and climate change initiatives on the Company's operations and operating costs; the expected benefits of the company's business venture with ConocoPhillips, including the impact on price risk and ability to achieve economic returns; the benefits of, and amount of CO₂ which may be sequestered at the Weyburn project; projected benefits which may be achieved from the use of wedge well technology and new water recycling technology at the Company's SAGD operations; the impact of Western Canada pipeline constraints and potential refinery disruptions on future Canadian crude oil prices; projections that the Company's Bankers' Acceptances and Commercial Paper Program will continue to be fully supported by committed credit facilities and term loan facilities; projections relating to the Deep Panuke project, including projected costs, production levels and the timing thereof and the timing for completion of project facilities; expected completion dates of the arrangements with Brown Southwest and Brown Haynesville; projections with respect to the proposed Arrangement, including the potential timing for the Arrangement and the conditions which are or may be required prior to proceeding, the expected future attributes of each of EnCana and Cenovus following any such Arrangement, and the anticipated benefits of the Arrangement; projections relating to the Company's natural gas, crude oil and natural gas liquids reserves; the Company's plans to renew its Canadian debt shelf prospectus; the expected results of the Company's cost containment and reduction strategies; the Company's assessment of counterparty credit risk and the potential impact thereof; the Company's ability to fund its 2009 capital program and pay dividends to shareholders; the impact of the current business market conditions, including the economic recession and financial market turmoil on the Company's operations and expected results; the effect of the Company's risk mitigation policies, systems, processes and insurance program; the Company's expectations for future Debt to Capitalization ratios; the expected impact and timing of various accounting pronouncements, rule changes and standards on the Company and its Consolidated Financial Statements; projections with respect to expected funding requirements of the Company's defined benefit pension plan and the materiality thereof; projected costs of payouts under the Company's Performance Tandem Share Appreciation Rights, Performance Share Appreciation Rights and Performance Share Units programs; and projections relating to North American conventional natural gas supplies and the ability of unconventional resource plays to offset future conventional gas production declines over the next few years. Readers are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur, which may cause the Company's actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These risks and uncertainties include, among other things: the ability to obtain any necessary approvals, waivers, consents, court orders and other requirements, including stabilization of financial and other markets necessary or desirable to permit or facilitate the Arrangement; the risk that any applicable conditions to complete the Arrangement may not occur or be satisfied; volatility of and assumptions regarding oil and gas prices; assumptions based upon EnCana's current guidance; fluctuations in currency and interest rates; product supply and demand; market competition; risks inherent in the Company's and its subsidiaries' marketing operations, including credit risks; imprecision of reserves estimates and estimates of recoverable quantities of oil, bitumen, natural gas and liquids from resource plays and other sources not currently classified as proved; the Company's and its subsidiaries' ability to replace and expand oil and gas reserves; the ability of the Company and ConocoPhillips to successfully manage and operate the North American integrated heavy oil business and the ability of the parties to obtain necessary regulatory approvals; refining and marketing margins; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; potential failure of new products to achieve acceptance in the market; unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities; unexpected difficulties in manufacturing, transporting or refining synthetic crude oil; risks associated with technology and the application thereof to the business of the Company and Cenovus; the Company's ability to generate sufficient cash flow from operations to meet its current and future obligations; the Company's ability to access external sources of debt and equity capital; the timing and the costs of well and pipeline construction; the Company's and its subsidiaries' ability to secure adequate product transportation; changes in royalty, tax, environmental, greenhouse gas, carbon and other laws or regulations or the interpretations of such laws or regulations; political and

economic conditions in the countries in which the Company and its subsidiaries operate; the risk of international war, hostilities, civil insurrection and instability affecting countries in which the Company and its subsidiaries operate and terrorist threats; risks associated with existing and potential future lawsuits and regulatory actions made against the Company and its subsidiaries; and other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by EnCana. Statements relating to "reserves" or "resources" or "resource potential" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the resources and reserves described exist in the quantities predicted or estimated, and can be profitably produced in the future. Although EnCana believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned that the foregoing list of important factors is not exhaustive. Furthermore, the forward-looking statements contained in this document are made as of the date of this document, and except as required by law, EnCana does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this document are expressly qualified by this cautionary statement.

The Company previously disclosed and updated guidance relating to anticipated results for 2008. There were no material differences between (a) the Company's actual cash flow, capital investment and operating costs in 2008 and (b) the amounts forecast in the Company's most recently disclosed guidance (dated December 11, 2008). Explanations for any changes contained in any updated guidance, from guidance previously disclosed, were provided in the news release issued by the Company at the time the guidance was updated.

Forward-looking information respecting anticipated 2009 cash flow, operating cash flow and pre-tax cash flow for EnCana is based upon achieving average production of oil and gas for 2009 of approximately 4.6 Bcfe/d, average commodity prices for 2009 of a WTI price of \$55/bbl to \$75/bbl for oil, a NYMEX price of \$5.50/Mcf to \$7.50/Mcf for natural gas, an average U.S./Canadian dollar foreign exchange rate of \$0.75 to \$0.85, an average Chicago 3-2-1 crack spread for 2009 of \$5.00/bbl to \$10.00/bbl for refining margins, and an average number of outstanding shares for EnCana of approximately 750 million. Forward-looking information respecting the proposed Arrangement is based upon the assumption that financial and other markets will stabilize. Assumptions relating to forward-looking statements generally include EnCana's current expectations and projections made by the Company in light of, and generally consistent with, its historical experience and its perception of historical trends, as well as expectations regarding rates of advancement and innovation, generally consistent with and informed by its past experience, all of which are subject to the risk factors identified elsewhere in this document.

EnCana is required to disclose events and circumstances that occurred during the period to which this MD&A relates that are reasonably likely to cause actual results to differ materially from material forward-looking statements for a period that is not yet complete that EnCana has previously disclosed to the public and the expected differences thereto. Such disclosure can be found in EnCana's news release dated February 12, 2009, which is available on EnCana's website at www.encana.com and on SEDAR at www.sedar.com.

OIL AND GAS INFORMATION

EnCana's disclosure of reserves data and other oil and gas information is made in reliance on an exemption granted to EnCana by Canadian securities regulatory authorities that permits it to provide such disclosure in accordance with U.S. disclosure requirements. The information provided by EnCana may differ from the corresponding information prepared in accordance with Canadian disclosure standards under NI 51-101. The reserves quantities disclosed by EnCana represent net proved reserves calculated using the standards contained in Regulation S-X of the U.S. Securities and Exchange Commission. Further information about the differences between the U.S. requirements and the NI 51-101 requirements is set forth under the heading "Note Regarding Reserves Data and Other Oil and Gas Information" in EnCana's Annual Information Form.

Crude Oil, NGLs and Natural Gas Conversions

In this document, certain crude oil and NGLs volumes have been converted to millions of cubic feet equivalent ("MMcfe") or thousands of cubic feet equivalent ("Mcf") on the basis of one barrel ("bbl") to six thousand cubic feet ("Mcf"). Also, certain natural gas volumes have been converted to barrels of oil equivalent ("BOE"), thousands of BOE ("MBOE") or millions of BOE ("MMBOE") on the same basis. MMcf, Mcf, BOE, MBOE and MMBOE may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent value equivalency at the well head.

Resource Play

Resource play is a term used by EnCana to describe an accumulation of hydrocarbons known to exist over a large areal expanse and/or thick vertical section, which when compared to a conventional play, typically has a lower geological and/or commercial development risk and lower average decline rate.

CURRENCY, NON-GAAP MEASURES AND REFERENCES TO ENCANA

All information included in this document and the Consolidated Financial Statements and comparative information is shown on a U.S. dollar, after royalties basis unless otherwise noted.

Non-GAAP Measures

Certain measures in this document do not have any standardized meaning as prescribed by Canadian GAAP such as Cash Flow, Cash Flow from Continuing Operations, Cash Flow per share – diluted, Free Cash Flow, Operating Earnings, Operating Earnings from Continuing Operations, Operating Earnings per share – diluted, Adjusted EBITDA, Debt, Net Debt and Capitalization and therefore are considered non-GAAP measures. Therefore, these measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in this document in order to provide shareholders and potential investors with additional information regarding the Company's liquidity and its ability to generate funds to finance its operations. Management's use of these measures has been disclosed further in Management's Discussion and Analysis dated February 19, 2009 contained in this Annual Report.

References to EnCana

For convenience, references in this document to "EnCana", the "Company", "we", "us", "our" and "its" may, where applicable, refer only to or include any relevant direct and indirect subsidiary corporations and partnerships ("Subsidiaries") of EnCana Corporation, and the assets, activities and initiatives of such Subsidiaries.

DIFFERENCES IN ENCANA'S CORPORATE GOVERNANCE PRACTICES COMPARED TO NYSE CORPORATE GOVERNANCE STANDARDS

As a Canadian company listed on the New York Stock Exchange ("NYSE"), EnCana is not required to comply with most of the NYSE Corporate Governance Standards and instead may comply with Canadian Corporate Governance Practices. EnCana is, however, required to disclose the significant differences between its corporate governance practices and the requirements applicable to U.S. companies listed on the NYSE under NYSE corporate governance standards. A summary of these significant differences is available on EnCana's website (www.encana.com). Except as described in this document, EnCana is in compliance with the NYSE corporate governance standards in all significant respects.

ADDITIONAL INFORMATION

Further information regarding EnCana Corporation can be accessed under the Company's public filings found at www.sedar.com and on the Company's website at www.encana.com.

Management Report

Management's Responsibility for Consolidated Financial Statements

The accompanying Consolidated Financial Statements of EnCana Corporation (the "Company") are the responsibility of Management. The Consolidated Financial Statements have been prepared by Management in United States dollars in accordance with Canadian generally accepted accounting principles and include certain estimates that reflect Management's best judgments. Financial information contained throughout the annual report is consistent with these financial statements.

The Company's Board of Directors has approved the information contained in the Consolidated Financial Statements. The Board of Directors fulfills its responsibility regarding the financial statements mainly through its Audit Committee, which has a written mandate that complies with the current requirements of Canadian securities legislation and the United States Sarbanes-Oxley Act of 2002 and voluntarily complies, in principle, with the Audit Committee guidelines of the New York Stock Exchange. The Audit Committee meets at least on a quarterly basis.

Management's Assessment of Internal Control Over Financial Reporting

Management is also responsible for establishing and maintaining adequate internal control over the Company's financial reporting. The internal control system was designed to provide reasonable assurance to the Company's Management regarding the preparation and presentation of the Consolidated Financial Statements.

Internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management has assessed the effectiveness of the Company's internal control over financial reporting as at December 31, 2008. In making its assessment, Management has used the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") framework in Internal Control – Integrated Framework to evaluate the effectiveness of the Company's internal control over financial reporting. Based on our evaluation, Management has concluded that the Company's internal control over financial reporting was effective as at that date.

PricewaterhouseCoopers LLP, an independent firm of chartered accountants, was appointed by a vote of shareholders at the Company's last annual meeting to audit and provide independent opinions on both the Consolidated Financial Statements and the Company's internal control over financial reporting as at December 31, 2008, as stated in their Auditors' Report. PricewaterhouseCoopers LLP has provided such opinions.



Randall K. Eresman
President &
Chief Executive Officer



Brian C. Ferguson
Executive Vice-President &
Chief Financial Officer

February 19, 2009

Auditors' Report

To the Shareholders of EnCana Corporation

We have completed integrated audits of EnCana Corporation's 2008, 2007 and 2006 consolidated financial statements and of its internal control over financial reporting as of December 31, 2008. Our opinions, based on our audits, are presented below.

Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of EnCana Corporation as at December 31, 2008 and December 31, 2007, and the related consolidated statements of earnings, retained earnings, comprehensive income, accumulated other comprehensive income, and cash flows for each of the years in the three year period ended December 31, 2008. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits of the Company's financial statements as at December 31, 2008 and December 31, 2007 and for each of the years in the three year period ended December 31, 2008 in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. A financial statement audit also includes assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as at December 31, 2008 and December 31, 2007 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2008 in accordance with Canadian generally accepted accounting principles.

Internal Control Over Financial Reporting

We have also audited EnCana Corporation's internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Assessment of Internal Control over Financial Reporting. Our responsibility is to express an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008 based on criteria established in Internal Control — Integrated Framework issued by the COSO.



PricewaterhouseCoopers LLP

Chartered Accountants

Calgary, Alberta

Canada

February 19, 2009

Consolidated Statement of Earnings

For the years ended December 31 (US\$ millions, except per share amounts)		2008	2007	2006
Revenues, Net of Royalties	(Note 5)	\$ 30,064	\$ 21,700	\$ 16,670
Expenses	(Note 5)			
Production and mineral taxes		478	291	349
Transportation and selling		1,704	1,264	1,341
Operating		2,475	2,278	1,655
Purchased product		11,186	8,583	2,862
Depreciation, depletion and amortization		4,223	3,816	3,112
Administrative		473	384	271
Interest, net	(Note 8)	586	428	396
Accretion of asset retirement obligation	(Note 16)	79	64	50
Foreign exchange (gain) loss, net	(Note 9)	423	(164)	14
(Gain) loss on divestitures	(Note 7)	(140)	(65)	(323)
		21,487	16,879	9,727
Net Earnings Before Income Tax		8,577	4,821	6,943
Income tax expense	(Note 10)	2,633	937	1,892
Net Earnings From Continuing Operations		5,944	3,884	5,051
Net Earnings From Discontinued Operations	(Note 6)	—	75	601
Net Earnings		\$ 5,944	\$ 3,959	\$ 5,652
Net Earnings From Continuing Operations per Common Share	(Note 21)			
Basic		\$ 7.92	\$ 5.13	\$ 6.16
Diluted		\$ 7.91	\$ 5.08	\$ 6.04
Net Earnings per Common Share	(Note 21)			
Basic		\$ 7.92	\$ 5.23	\$ 6.89
Diluted		\$ 7.91	\$ 5.18	\$ 6.76

See accompanying Notes to Consolidated Financial Statements

Consolidated Statement of Retained Earnings

For the years ended December 31 (US\$ millions)	2008	2007	2006
Retained Earnings, Beginning of Year	\$ 13,082	\$ 11,344	\$ 9,481
Net Earnings	5,944	3,959	5,652
Dividends on Common Shares	(1,199)	(603)	(304)
Charges for Normal Course Issuer Bid <small>(Note 17)</small>	(243)	(1,618)	(3,485)
Retained Earnings, End of Year	\$ 17,584	\$ 13,082	\$ 11,344

Consolidated Statement of Comprehensive Income

For the years ended December 31 (US\$ millions)	2008	2007	2006
Net Earnings	\$ 5,944	\$ 3,959	\$ 5,652
Other Comprehensive Income, Net of Tax			
Foreign Currency Translation Adjustment	(2,230)	1,688	113
Comprehensive Income	\$ 3,714	\$ 5,647	\$ 5,765

Consolidated Statement of Accumulated Other Comprehensive Income

For the years ended December 31 (US\$ millions)	2008	2007	2006
Accumulated Other Comprehensive Income, Beginning of Year	\$ 3,063	\$ 1,375	\$ 1,262
Foreign Currency Translation Adjustment	(2,230)	1,688	113
Accumulated Other Comprehensive Income, End of Year	\$ 833	\$ 3,063	\$ 1,375

See accompanying Notes to Consolidated Financial Statements

Consolidated Balance Sheet

As at December 31 (US\$ millions)

	2008	2007
Assets		
Current Assets		
Cash and cash equivalents	\$ 383	\$ 553
Accounts receivable and accrued revenues	1,568	2,381
Current portion of partnership contribution receivable	(Notes 4, 11) 313	297
Risk management	(Note 20) 2,818	385
Inventories	(Note 12) 520	828
	5,602	4,444
Property, Plant and Equipment, net	(Notes 5, 13) 35,424	35,865
Investments and Other Assets	(Note 14) 727	607
Partnership Contribution Receivable	(Notes 4, 11) 2,834	3,147
Risk Management	(Note 20) 234	18
Goodwill	(Note 5) 2,426	2,893
	(Note 5) \$ 47,247	\$ 46,974
Liabilities and Shareholders' Equity		
Current Liabilities		
Accounts payable and accrued liabilities	\$ 2,871	\$ 3,982
Income tax payable	424	1,150
Current portion of partnership contribution payable	(Notes 4, 11) 306	288
Risk management	(Note 20) 43	207
Current portion of long-term debt	(Note 15) 250	703
	3,894	6,330
Long-Term Debt	(Note 15) 8,755	8,840
Other Liabilities	576	242
Partnership Contribution Payable	(Notes 4, 11) 2,857	3,163
Risk Management	(Note 20) 7	29
Asset Retirement Obligation	(Note 16) 1,265	1,458
Future Income Taxes	(Note 10) 6,919	6,208
	24,273	26,270
Commitments and Contingencies	(Note 22)	
Shareholders' Equity		
Share capital	(Note 17) 4,557	4,479
Paid in surplus	(Note 17) -	80
Retained earnings	17,584	13,082
Accumulated other comprehensive income	833	3,063
Total Shareholders' Equity	22,974	20,704
	\$ 47,247	\$ 46,974

See accompanying Notes to Consolidated Financial Statements

Approved by the Board

David P. O'Brien, Director

Barry W. Harrison, Director

Consolidated Statement of Cash Flows

For the years ended December 31 (US\$ millions)	2008	2007	2006
Operating Activities			
Net earnings from continuing operations	\$ 5,944	\$ 3,884	\$ 5,051
Depreciation, depletion and amortization	4,223	3,816	3,112
Future income taxes	(Note 10) 1,646	(617)	950
Cash tax on sale of assets	(Note 10) 25	—	49
Unrealized (gain) loss on risk management	(Note 20) (2,729)	1,235	(2,060)
Unrealized foreign exchange (gain) loss	417	41	—
Accretion of asset retirement obligation	(Note 16) 79	64	50
(Gain) loss on divestitures	(Note 7) (140)	(65)	(323)
Other	(79)	95	214
Cash flow from discontinued operations	—	—	118
Net change in other assets and liabilities	(262)	(16)	138
Net change in non-cash working capital from continuing operations	(Note 21) (269)	(8)	3,343
Net change in non-cash working capital from discontinued operations	—	—	(2,669)
Cash From Operating Activities	8,855	8,429	7,973
Investing Activities			
Capital expenditures	(Note 5) (8,254)	(8,737)	(6,600)
Proceeds from divestitures	(Note 7) 904	481	689
Cash tax on sale of assets	(Note 10) (25)	—	(49)
Net change in investments and other	(267)	(5)	2
Net change in non-cash working capital from continuing operations	(Note 21) 89	86	19
Discontinued operations	—	—	2,557
Cash (Used in) Investing Activities	(7,553)	(8,175)	(3,382)
Financing Activities			
Net issuance (repayment) of revolving long-term debt	(53)	181	134
Issuance of long-term debt	(Note 15) 723	2,409	—
Repayment of long-term debt	(Note 15) (664)	(257)	(73)
Issuance of common shares	(Note 17) 80	176	179
Purchase of common shares	(Note 17) (326)	(2,025)	(4,219)
Dividends on common shares	(1,199)	(603)	(304)
Other	—	—	(11)
Cash (Used in) Financing Activities	(1,439)	(119)	(4,294)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	(33)	16	—
Increase (Decrease) in Cash and Cash Equivalents	(170)	151	297
Cash and Cash Equivalents, Beginning of Year	553	402	105
Cash and Cash Equivalents, End of Year	\$ 383	\$ 553	\$ 402

Supplemental Cash Flow Information (Note 21)

See accompanying Notes to Consolidated Financial Statements

Notes to Consolidated Financial Statements

Prepared using Canadian Generally Accepted Accounting Principles

All amounts in US\$ millions, unless otherwise indicated

For the year ended December 31, 2008

1. Summary of Significant Accounting Policies

In these Consolidated Financial Statements, unless otherwise indicated, all dollar amounts are expressed in United States (U.S.) dollars. EnCana's functional currency is Canadian dollars; EnCana has adopted the U.S. dollar as its reporting currency since most of its revenue is closely tied to the U.S. dollar and to facilitate a more direct comparison to other North American oil and gas companies. All references to US\$ or to \$ are to United States dollars and references to C\$ are to Canadian dollars.

EnCana's continuing operations are in the business of the exploration for, the development of, and the production and marketing of natural gas, crude oil and natural gas liquids ("NGLs"), refining operations and power generation operations.

A) PRINCIPLES OF CONSOLIDATION

The Consolidated Financial Statements include the accounts of EnCana Corporation and its subsidiaries ("EnCana" or the "Company"), and are presented in accordance with Canadian generally accepted accounting principles ("GAAP"). Information prepared in accordance with GAAP in the United States is included in Note 23.

Investments in jointly controlled partnerships and unincorporated joint ventures carry on EnCana's exploration, development, production and crude oil refining businesses and are accounted for using the proportionate consolidation method, whereby EnCana's proportionate share of revenues, expenses, assets and liabilities are included in the accounts.

Investments in companies and partnerships in which EnCana does not have direct or joint control over the strategic operating, investing and financing decisions, but does have significant influence on them, are accounted for using the equity method.

B) FOREIGN CURRENCY TRANSLATION

The accounts of self-sustaining operations are translated using the current rate method, whereby assets and liabilities are translated at period end exchange rates, while revenues and expenses are translated using average rates over the period. Translation gains and losses relating to the self-sustaining operations are included in Accumulated Other Comprehensive Income ("AOCI") as a separate component of Shareholders' Equity. As at December 31, 2008, AOCI is comprised solely of foreign currency translation adjustments.

Monetary assets and liabilities of the Company that are denominated in foreign currencies are translated into its functional currency at the rates of exchange in effect at the period end date. Any gains or losses are recorded in the Consolidated Statement of Earnings.

C) MEASUREMENT UNCERTAINTY

The timely preparation of the Consolidated Financial Statements in conformity with Canadian GAAP requires that Management make estimates and assumptions and use judgment regarding the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the Consolidated Financial Statements and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as of the date of the Consolidated Financial Statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

Amounts recorded for depreciation, depletion and amortization, asset retirement costs and obligations and amounts used for ceiling test and impairment calculations are based on estimates of natural gas and crude oil reserves and future costs required to develop those reserves. By their nature, these estimates of reserves, including the estimates of future prices, costs and the related future cash flows, are subject to measurement uncertainty. Accordingly, the impact in the Consolidated Financial Statements of future periods could be material.

The values of pension assets and obligations and the amount of pension costs charged to net earnings depend on certain actuarial and economic assumptions which, by their nature, are subject to measurement uncertainty.

The amount of compensation expense accrued for long-term performance-based compensation arrangements is subject to Management's best estimate of whether or not the performance criteria will be met and what the ultimate payout will be.

The estimated fair value of financial assets and liabilities, by their very nature, are subject to measurement uncertainty.

Tax interpretations, regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change. As such, income taxes are subject to measurement uncertainty.

D) REVENUErecognition

Revenues associated with the sales of EnCana's natural gas, crude oil, NGLs and petroleum and chemical products are recognized when title passes from the Company to its customer. Natural gas and crude oil produced and sold by EnCana below or above its working interest share in the related resource properties results in production underliftings or overliftings. Underliftings are recorded as inventory and overliftings are recorded as deferred revenue. Realized gains and losses from the Company's natural gas and crude oil commodity price risk management activities are recorded in revenue when the product is sold.

Market optimization revenues and purchased product are recorded on a gross basis when EnCana takes title to product and has risks and rewards of ownership. Purchases and sales of products that are entered into in contemplation of each other with the same counterparty are recorded on a net basis. Revenues associated with the services provided where EnCana acts as agent are recorded as the services are provided. Sales of electric power are recognized when power is provided to the customer.

Unrealized gains and losses from the Company's natural gas and crude oil commodity price risk management activities are recorded as revenue based on the related mark-to-market calculations at the end of the respective period.

E) PRODUCTION AND MINERAL TAXES

Costs paid by EnCana to non-mineral interest owners based on production of natural gas, crude oil and NGLs are recognized when the product is produced.

F) TRANSPORTATION AND SELLING COSTS

Costs paid by EnCana for the transportation and selling of natural gas, crude oil and NGLs, including diluent, are recognized when the product is delivered and the services provided.

G) EMPLOYEE BENEFIT PLANS

EnCana accrues for its obligations under its employee benefit plans and the related costs, net of plan assets.

The cost of pensions and other post-employment benefits is actuarially determined using the projected benefit method based on length of service, and reflects Management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected future health care costs. The expected return on plan assets is based on the fair value of those assets. The accrued benefit obligation is discounted using the market interest rate on high quality corporate debt instruments as at the measurement date.

Pension expense for the defined benefit pension plan includes the cost of pension benefits earned during the current year, the interest cost on pension obligations, the expected return on pension plan assets, the amortization of the net transitional obligation, the amortization of adjustments arising from pension plan amendments and the amortization of the excess of the net actuarial gain or loss over 10 percent of the greater of the benefit obligation and the fair value of plan assets. Amortization is done on a straight-line basis over a period covering the expected average remaining service lives of employees covered by the plans.

Pension expense for the defined contribution pension plans is recorded as the benefits are earned by the employees covered by the plans.

H) INCOME TAXES

EnCana follows the liability method of accounting for income taxes. Under this method, future income taxes are recorded for the effect of any difference between the accounting and income tax basis of an asset or liability, using the substantively enacted income tax rates. Accumulated future income tax balances are adjusted to reflect changes in income tax rates that are substantively enacted with the adjustment being recognized in net earnings in the period that the change occurs.

I) EARNINGS PER SHARE AMOUNTS

Basic net earnings per common share is computed by dividing the net earnings by the weighted average number of common shares outstanding during the period. Diluted net earnings per share amounts are calculated giving effect to the potential dilution that would occur if stock options, without tandem share appreciation rights attached, were exercised or other contracts to issue common shares were exercised or converted to common shares. The treasury stock method is used to determine the dilutive effect of stock options without tandem share appreciation rights attached and other dilutive instruments. The treasury stock method assumes that proceeds received from the exercise of in-the-money stock options without tandem share appreciation rights attached are used to repurchase common shares at the average market price.

J) CASH AND CASH EQUIVALENTS

Cash and cash equivalents include short-term investments, such as money market deposits or similar type instruments, with a maturity of three months or less when purchased.

K) INVENTORIES

Product inventories, including petroleum and chemical products, are valued at the lower of cost and net realizable value on a first-in, first-out or weighted average cost basis.

L) PROPERTY, PLANT AND EQUIPMENT

UPSTREAM

EnCana accounts for natural gas and crude oil properties in accordance with the Canadian Institute of Chartered Accountants' ("CICA") guideline on full cost accounting in the oil and gas industry. Under this method, all costs, including internal costs and asset retirement costs, directly associated with the acquisition of, the exploration for, and the development of natural gas and crude oil reserves are capitalized on a country-by-country cost centre basis.

Costs accumulated within each cost centre are depreciated, depleted and amortized using the unit-of-production method based on estimated proved reserves determined using estimated future prices and costs. For purposes of this calculation, oil is converted to gas on an energy equivalent basis. Capitalized costs subject to depletion include estimated future costs to be incurred in developing proved reserves. Proceeds from the divestiture of properties are normally deducted from the full cost pool without recognition of gain or loss unless that deduction would result in a change to the rate of depreciation, depletion and amortization of 20 percent or greater, in which case a gain or loss is recorded. Costs of major development projects and costs of acquiring and evaluating significant unproved properties are excluded, on a cost centre basis, from the costs subject to depletion until it is determined whether or not proved reserves are attributable to the properties, or impairment has occurred. Costs that have been impaired are included in the costs subject to depreciation, depletion and amortization.

An impairment loss is recognized in net earnings when the carrying amount of a cost centre is not recoverable and the carrying amount of the cost centre exceeds its fair value. The carrying amount of the cost centre is not recoverable if the carrying amount exceeds the sum of the undiscounted cash flows from proved reserves. If the sum of the cash flows is less than the carrying amount, the impairment loss is limited to the amount by which the carrying amount exceeds the sum of:

- i) the fair value of proved and probable reserves; and
- ii) the costs of unproved properties that have been subject to a separate impairment test.

DOWNSTREAM REFINING

The initial acquisition costs of refinery property, plant and equipment are capitalized when incurred. Costs include the cost of constructing or otherwise acquiring the equipment or facilities, the cost of installing the asset and making it ready for its intended use and the associated asset retirement costs. Capitalized costs are not subject to depreciation until the asset is put into use, after which they are depreciated on a straight-line basis over their estimated service lives of approximately 25 years.

An impairment loss is recognized on refinery property, plant and equipment when the carrying amount is not recoverable and exceeds its fair value. The carrying amount is not recoverable if the carrying amount exceeds the sum of the undiscounted cash flows from expected use and eventual disposition. If the carrying amount is not recoverable, an impairment loss is measured as the amount by which the refinery asset exceeds the fair value.

MARKET OPTIMIZATION

Midstream facilities, including power generation facilities, are carried at cost and depreciated on a straight-line basis over the estimated service lives of the assets, which range from 20 to 25 years. Capital assets related to pipelines are carried at cost and depreciated using the straight-line method over their economic lives, which range from 20 to 35 years.

CORPORATE

Costs associated with office furniture, fixtures, leasehold improvements, information technology and aircraft are carried at cost and depreciated on a straight-line basis over the estimated service lives of the assets, which range from three to 25 years. Assets under construction are not subject to depreciation until put into use. Land is carried at cost.

M) CAPITALIZATION OF COSTS

Expenditures related to renewals or betterments that improve the productive capacity or extend the life of an asset are capitalized. Maintenance and repairs are expensed as incurred.

Interest is capitalized during the construction phase of large capital projects.

N) AMORTIZATION OF OTHER ASSETS

Items included in Investments and Other Assets are amortized, where applicable, on a straight-line basis over the estimated useful lives of the assets.

O) GOODWILL

Goodwill, which represents the excess of purchase price over fair value of net assets acquired, is assessed for impairment at least annually. Goodwill and all other assets and liabilities have been allocated to the country cost centre levels, referred to as reporting units. To assess impairment, the fair value of each reporting unit is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, then a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill and comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of goodwill over the implied fair value of goodwill is the impairment amount.

P) ASSET RETIREMENT OBLIGATION

The fair value of estimated asset retirement obligations is recognized in the Consolidated Balance Sheet when incurred and a reasonable estimate of fair value can be made.

Asset retirement obligations include those legal obligations where the Company will be required to retire tangible long-lived assets such as producing well sites, offshore production platforms, natural gas processing plants, and refining facilities. The asset retirement cost, equal to the initially estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long-lived asset. Changes in the estimated obligation resulting from revisions to estimated timing or amount of undiscounted cash flows are recognized as a change in the asset retirement obligation and the related asset retirement cost.

Amortization of asset retirement costs are included in depreciation, depletion and amortization in the Consolidated Statement of Earnings. Increases in the asset retirement obligation resulting from the passage of time are recorded as accretion of asset retirement obligation in the Consolidated Statement of Earnings.

Actual expenditures incurred are charged against the accumulated obligation.

Q) STOCK-BASED COMPENSATION

Obligations for payments, cash or common shares, under the Company's share appreciation rights, stock options with tandem share appreciation rights attached, deferred share and performance share units plans are accrued as compensation expense over the vesting period. Fluctuations in the price of EnCana's common shares change the accrued compensation expense and are recognized when they occur.

R) FINANCIAL INSTRUMENTS

Financial instruments are measured at fair value on initial recognition of the instrument, except for certain related party transactions. Measurement in subsequent periods depends on whether the financial instrument has been classified as "held-for-trading", "available-for-sale", "held-to-maturity", "loans and receivables", or "other financial liabilities" as defined by the accounting standard.

Financial assets and financial liabilities "held-for-trading" are measured at fair value with changes in those fair values recognized in net earnings. Financial assets "available-for-sale" are measured at fair value, with changes in those fair values recognized in Other Comprehensive Income ("OCI"). Financial assets "held-to-maturity", "loans and receivables" and "other financial liabilities" are measured at amortized cost using the effective interest method of amortization.

Cash and cash equivalents are designated as "held-for-trading" and are measured at fair value. Accounts receivable and accrued revenues and the partnership contribution receivable are designated as "loans and receivables". Accounts payable and accrued liabilities, the partnership contribution payable and long-term debt are designated as "other financial liabilities". EnCana capitalizes long-term debt transaction costs, premiums and discounts. These costs are capitalized within long-term debt and amortized using the effective interest method.

DERIVATIVE FINANCIAL INSTRUMENTS

Risk management assets and liabilities are derivative financial instruments classified as "held-for-trading" unless designated for hedge accounting. Derivative instruments that do not qualify as hedges, or are not designated as hedges, are recorded using the mark-to-market method of accounting whereby instruments are recorded in the Consolidated Balance Sheet as either an asset or liability with changes in fair value recognized in net earnings. Realized gains or losses from financial derivatives related to natural gas and crude oil commodity prices are recognized in natural gas and crude oil revenues as the related sales occur. Realized gains or losses from financial derivatives related to power commodity prices are recognized in operating costs as the related power costs are incurred. Unrealized gains and losses are recognized at the end of each respective reporting period. The estimated fair value of all derivative instruments is based on quoted market prices or, in their absence, third-party market indications and forecasts.

Derivative financial instruments are used by EnCana to manage economic exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. The Company's policy is not to utilize derivative financial instruments for speculative purposes.

EnCana has in place policies and procedures with respect to the required documentation and approvals for the use of derivative financial instruments and specifically ties their use, in the case of commodities, to the mitigation of market price risk associated with cash flows expected to be generated from budgeted capital programs, and in other cases to the mitigation of market price risks for specific assets and obligations. When applicable, the Company identifies relationships between financial instruments and anticipated transactions, as well as its risk management objective and the strategy for undertaking the economic hedge transaction. Where specific financial instruments are executed, the Company assesses, both at the time of purchase and on an ongoing basis, whether the financial instrument used in the particular transaction is effective in offsetting changes in fair values or cash flows of the transaction.

S) RECENT ACCOUNTING PRONOUNCEMENTS

The Company has assessed new and revised accounting pronouncements that have been issued that are not yet effective and determined that the following may have an impact on the Company:

- As of January 1, 2009, EnCana will be required to adopt the CICA Handbook Section 3064, "Goodwill and Intangible Assets", which will replace the existing Goodwill and Intangible Assets standard. The new standard revises the requirement for recognition, measurement, presentation and disclosure of intangible assets. The adoption of this standard should not have a material impact on EnCana's Consolidated Financial Statements.
- In February 2008, the CICA's Accounting Standards Board confirmed that International Financial Reporting Standards ("IFRS") will replace Canadian GAAP in 2011 for profit-oriented Canadian publicly accountable enterprises. EnCana will be required to report its results in accordance with IFRS beginning in 2011. The Company has developed a changeover plan to complete the transition to IFRS by January 1, 2011, including the preparation of required comparative information.

The key elements of EnCana's changeover plan include:

- determine appropriate changes to accounting policies and required amendments to financial disclosures;
- identify and implement changes in associated processes and information systems;
- comply with internal control requirements;
- communicate collateral impacts to internal business groups; and
- educate and train internal and external stakeholders.

The Company is currently analyzing accounting policy alternatives and identifying implementation options for the corresponding process changes. EnCana will update its IFRS changeover plan to reflect new and amended accounting standards issued by the International Accounting Standards Board. As IFRS is expected to change prior to 2011, the impact of IFRS on the Company's Consolidated Financial Statements is not reasonably determinable at this time.

T) RECLASSIFICATION

Certain information provided for prior years has been reclassified to conform to the presentation adopted in 2008.

2. Changes in Accounting Policies and Practices

On January 1, 2008, the Company adopted the following CICA Handbook Sections:

- "Inventories", Section 3031. The new standard replaces the previous inventories standard and requires inventory to be valued on a first-in, first-out or weighted average cost basis, which is consistent with EnCana's former accounting policy. The new standard allows the reversal of previous write-downs to net realizable value when there is a subsequent increase in the value of inventories. The adoption of this standard has had no material impact on EnCana's Consolidated Financial Statements.
- "Financial Instruments – Presentation", Section 3863 and "Financial Instruments – Disclosures", Section 3862. The new disclosure standard increases EnCana's disclosure regarding the nature and extent of the risks associated with financial instruments and how those risks are managed (See Note 20). The new presentation standard carries forward the former presentation requirements.
- "Capital Disclosures", Section 1535. The new standard requires EnCana to disclose its objectives, policies and processes for managing its capital structure (See Note 18).

3. Proposed Corporate Reorganization

On May 11, 2008, EnCana announced its plans to split into two independent energy companies – one a North American natural gas company and the other a fully integrated oil company with in-situ oil properties and refineries supplemented by reliable production from various natural gas and crude oil resource plays.

The proposed corporate reorganization (the "Arrangement") would be implemented through a court approved Plan of Arrangement and is subject to shareholder approval. The Arrangement would result in two publicly traded entities with the names of Cenovus Energy Inc. ("Cenovus") and EnCana Corporation. Each EnCana shareholder would receive one share of each entity in exchange for each EnCana Common Share held. On October 15, 2008, EnCana announced the proposed Arrangement would be delayed until the global debt and equity markets regain stability.

4. Joint Venture with ConocoPhillips

On January 2, 2007, EnCana became a 50 percent partner in an integrated, North American oil business with ConocoPhillips which consists of an upstream and a downstream entity. The upstream entity contribution included assets from EnCana, primarily the Foster Creek and Christina Lake properties, with a fair value of \$7.5 billion and a note receivable contributed from ConocoPhillips of an equal amount. For the downstream entity, ConocoPhillips contributed its Wood River and Borger refineries, located in Illinois and Texas, respectively, for a fair value of \$7.5 billion and EnCana contributed a note payable of \$7.5 billion. Further information about these notes is included in Note 11.

In accordance with Canadian GAAP, these entities have been accounted for using the proportionate consolidation method with the results of operations included in the Integrated Oil Division (See Note 5).

5. Segmented Information

The Company's operating and reportable segments are as follows:

- **Canada** includes the Company's exploration for, and development and production of natural gas, crude oil and NGLs and other related activities within the Canadian cost centre.
- **USA** includes the Company's exploration for, and development and production of natural gas, NGLs and other related activities within the United States cost centre.
- **Downstream Refining** is focused on the refining of crude oil into petroleum and chemical products at two refineries located in the United States. The refineries are jointly owned with ConocoPhillips.
- **Market Optimization** is primarily responsible for the sale of the Company's proprietary production. These results are included in the Canada and USA segments. Market optimization activities include third-party purchases and sales of product that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification. These activities are reflected in the Market Optimization segment.
- **Corporate and Other** mainly includes unrealized gains or losses recorded on derivative financial instruments. Once amounts are settled, the realized gains and losses are recorded in the operating segment to which the derivative instrument relates.

Market Optimization markets substantially all of the Company's upstream production to third-party customers. Transactions between segments are based on market values and eliminated on consolidation. The tables in this note present financial information on an after eliminations basis.

EnCana has updated its segmented reporting to present the upstream Canadian and United States cost centres and Downstream Refining as separate reportable segments. This results in EnCana presenting the Canadian portion of the Integrated Oil Division as part of the Canada segment. Previously, this was aggregated and presented in the Integrated Oil segment. Prior periods have been restated to reflect the new presentation.

EnCana has a decentralized decision making and reporting structure. Accordingly, the Company is organized into Divisions as follows:

- **Canadian Plains** Division includes natural gas production and crude oil development and production assets located in eastern Alberta and Saskatchewan.
- **Canadian Foothills** Division includes natural gas development and production assets located in western Alberta and British Columbia as well as the Company's Canadian offshore assets.
- **USA** Division includes the assets located in the United States and comprises the USA segment described above.
- **Integrated Oil** Division is the combined total of Integrated Oil – Canada and Downstream Refining. Integrated Oil – Canada includes the Company's exploration for, and development and production of bitumen using in-situ recovery methods. Integrated Oil – Canada is composed of EnCana's interests in the FCCL Oil Sands Partnership jointly owned with ConocoPhillips, the Athabasca natural gas assets and other bitumen interests.

Operations that have been discontinued are disclosed in Note 6.

Results of Continuing Operations
Segment and Geographic Information

	Canada			USA			Downstream Refining		
	2008	2007	2006	2008	2007	2006	2008	2007	2006
For the years ended December 31									
Revenues, Net of Royalties	\$ 10,050	\$ 8,308	\$ 8,266	\$ 5,629	\$ 4,372	\$ 3,345	\$ 9,011	\$ 7,315	\$ -
Expenses									
Production and mineral taxes	108	102	116	370	189	233	-	-	-
Transportation and selling	1,202	947	1,077	502	307	248	-	-	-
Operating	1,333	1,204	1,104	618	595	490	492	428	-
Purchased product	(151)	(88)	-	-	-	-	8,760	5,813	-
	7,558	6,143	5,969	4,139	3,281	2,374	(241)	1,074	-
Depreciation, depletion and amortization	2,198	2,298	2,146	1,691	1,181	869	188	159	-
Segment Income (Loss)	\$ 5,360	\$ 3,845	\$ 3,823	\$ 2,448	\$ 2,100	\$ 1,505	\$ (429)	\$ 915	\$ -

	Market Optimization			Corporate & Other			Consolidated		
	2008	2007	2006	2008	2007	2006	2008	2007	2006
Revenues, Net of Royalties	\$ 2,655	\$ 2,944	\$ 3,007	\$ 2,719	\$ (1,239)	\$ 2,052	\$ 30,064	\$ 21,700	\$ 16,670
Expenses									
Production and mineral taxes	-	-	-	-	-	-	478	291	349
Transportation and selling	-	10	16	-	-	-	1,704	1,264	1,341
Operating	45	37	62	(13)	14	(1)	2,475	2,278	1,655
Purchased product	2,577	2,858	2,862	-	-	-	11,186	8,583	2,862
	33	39	67	2,732	(1,253)	2,053	14,221	9,284	10,463
Depreciation, depletion and amortization	15	17	12	131	161	85	4,223	3,816	3,112
Segment Income (Loss)	\$ 18	\$ 22	\$ 55	\$ 2,601	\$ (1,414)	\$ 1,968	\$ 9,998	\$ 5,468	\$ 7,351
Administrative							473	384	271
Interest, net							586	428	396
Accretion of asset retirement obligation							79	64	50
Foreign exchange (gain) loss, net							423	(164)	14
(Gain) loss on divestitures							(140)	(65)	(323)
							1,421	647	408
Net Earnings Before Income Tax							\$ 8,577	\$ 4,821	\$ 6,943
Income tax expense							2,633	937	1,892
Net Earnings from Continuing Operations							\$ 5,944	\$ 3,884	\$ 5,051

Results of Continuing Operations

Product and Divisional Information

	Canada Segment								
	Canadian Plains			Canadian Foothills			Integrated Oil – Canada		
For the years ended December 31	2008	2007	2006	2008	2007	2006	2008	2007	2006
Revenues, Net of Royalties	\$ 4,418	\$ 3,652	\$ 3,559	\$ 4,355	\$ 3,679	\$ 3,338	\$ 1,277	\$ 977	\$ 1,369
Expenses									
Production and mineral taxes	74	63	72	33	39	43	1	–	1
Transportation and selling	392	345	353	239	201	194	571	401	530
Operating	484	440	387	609	535	439	240	229	278
Purchased product	–	–	–	–	–	–	(151)	(88)	–
Operating Cash Flow	\$ 3,468	\$ 2,804	\$ 2,747	\$ 3,474	\$ 2,904	\$ 2,662	\$ 616	\$ 435	\$ 560
	Total								
							2008	2007	2006
Revenues, Net of Royalties							\$ 10,050	\$ 8,308	\$ 8,266
Expenses									
Production and mineral taxes							108	102	116
Transportation and selling							1,202	947	1,077
Operating							1,333	1,204	1,104
Purchased product							(151)	(88)	–
Operating Cash Flow							\$ 7,558	\$ 6,143	\$ 5,969

Results of Continuing Operations
Product and Divisional Information

Canadian Plains Division										
	Gas			Oil & NGLs			Other			
For the years ended December 31	2008	2007	2006	2008	2007	2006	2008	2007	2006	
Revenues, Net of Royalties	\$ 2,301	\$ 2,186	\$ 2,213	\$ 2,106	\$ 1,453	\$ 1,337	\$ 11	\$ 13	\$ 9	
Expenses										
Production and mineral taxes	36	34	41	38	29	31	—	—	—	
Transportation and selling	71	82	77	321	263	276	—	—	—	
Operating	241	221	194	239	215	188	4	4	5	
Operating Cash Flow	\$ 1,953	\$ 1,849	\$ 1,901	\$ 1,508	\$ 946	\$ 842	\$ 7	\$ 9	\$ 4	
Total										
							2008			2006
Revenues, Net of Royalties				\$ 4,418			\$ 3,652	\$ 3,559		
Expenses							74	63	72	
Production and mineral taxes							392	345	353	
Transportation and selling							484	440	387	
Operating										
Operating Cash Flow				\$ 3,468			\$ 2,804	\$ 2,747		
Canadian Foothills Division										
	Gas			Oil & NGLs			Other			
For the years ended December 31	2008	2007	2006	2008	2007	2006	2008	2007	2006	
Revenues, Net of Royalties	\$ 3,720	\$ 3,232	\$ 2,936	\$ 578	\$ 390	\$ 360	\$ 57	\$ 57	\$ 42	
Expenses										
Production and mineral taxes	28	36	39	5	3	4	—	—	—	
Transportation and selling	201	192	186	12	9	8	26	—	—	
Operating	549	482	394	39	33	34	21	20	11	
Operating Cash Flow	\$ 2,942	\$ 2,522	\$ 2,317	\$ 522	\$ 345	\$ 314	\$ 10	\$ 37	\$ 31	
Total										
							2008			2006
Revenues, Net of Royalties				\$ 4,355			\$ 3,679	\$ 3,338		
Expenses							33	39	43	
Production and mineral taxes							239	201	194	
Transportation and selling							609	535	439	
Operating										
Operating Cash Flow				\$ 3,474			\$ 2,904	\$ 2,662		

Results of Continuing Operations

Product and Divisional Information

	USA Division									
	Gas			Oil & NGLs			Other			
For the years ended December 31	2008	2007	2006	2008	2007	2006	2008	2007	2006	
Revenues, Net of Royalties	\$ 4,934	\$ 3,765	\$ 2,854	\$ 407	\$ 309	\$ 267	\$ 288	\$ 298	\$ 224	
Expenses										
Production and mineral taxes	334	167	213	36	22	20	-	-	-	
Transportation and selling	502	307	248	-	-	-	-	-	-	
Operating	352	323	283	-	-	-	266	272	207	
Operating Cash Flow	\$ 3,746	\$ 2,968	\$ 2,110	\$ 371	\$ 287	\$ 247	\$ 22	\$ 26	\$ 17	
	Total									
							2008	2007	2006	
Revenues, Net of Royalties							\$ 5,629	\$ 4,372	\$ 3,345	
Expenses										
Production and mineral taxes							370	189	233	
Transportation and selling							502	307	248	
Operating							618	595	490	
Operating Cash Flow							\$ 4,139	\$ 3,281	\$ 2,374	
	Integrated Oil Division									
	Oil ⁽¹⁾			Downstream Refining			Other ⁽¹⁾			
For the years ended December 31	2008	2007	2006	2008	2007	2006	2008	2007	2006	
Revenues, Net of Royalties	\$ 1,117	\$ 738	\$ 941	\$ 9,011	\$ 7,315	\$ -	\$ 160	\$ 239	\$ 428	
Expenses										
Production and mineral taxes	-	-	-	-	-	-	1	-	1	
Transportation and selling	526	366	476	-	-	-	45	35	54	
Operating	170	159	194	492	428	-	70	70	84	
Purchased product	-	-	-	8,760	5,813	-	(151)	(88)	-	
Operating Cash Flow	\$ 421	\$ 213	\$ 271	\$ (241)	\$ 1,074	\$ -	\$ 195	\$ 222	\$ 289	
	Total									
							2008	2007	2006	
Revenues, Net of Royalties							\$ 10,288	\$ 8,292	\$ 1,369	
Expenses										
Production and mineral taxes							1	-	1	
Transportation and selling							571	401	530	
Operating							732	657	278	
Purchased product							8,609	5,725	-	
Operating Cash Flow							\$ 375	\$ 1,509	\$ 560	

(1) Oil and Other comprise Integrated Oil – Canada. Other includes production of natural gas and bitumen from the Athabasca and Senlac properties.

Capital Expenditures (Continuing Operations)

For the years ended December 31

	2008	2007	2006
Capital			
Canadian Plains	\$ 847	\$ 846	\$ 770
Canadian Foothills	2,299	2,439	2,500
Integrated Oil – Canada	656	451	745
Canada	3,802	3,736	4,015
USA	2,615	1,919	2,061
Downstream Refining	478	220	–
Market Optimization	17	6	44
Corporate & Other	168	154	149
	7,080	6,035	6,269
Acquisition Capital			
Canadian Foothills	151	75	26
Integrated Oil – Canada	–	14	21
Canada	151	89	47
USA	1,023	2,613	284
	1,174	2,702	331
Total	\$ 8,254	\$ 8,737	\$ 6,600

On September 25, 2008, EnCana acquired certain land and property in Louisiana for approximately \$101 million before closing adjustments. The purchase was facilitated by an unrelated party, Brown Haynesville Leasehold LLC ("Brown Haynesville"), which holds the majority of the assets in trust for the Company in anticipation of a qualifying like kind exchange for U.S. tax purposes.

On July 23, 2008, EnCana acquired certain land and mineral interests in Louisiana for approximately \$457 million before closing adjustments. The purchase was facilitated by an unrelated party, Brown Southwest Minerals LLC ("Brown Southwest"), which holds the majority of the assets in trust for the Company in anticipation of a qualifying like kind exchange for U.S. tax purposes. On November 12, 2008, an unrelated party exercised an option to purchase certain interests as part of the above acquisition for approximately \$157 million, reducing the qualifying like kind exchange to approximately \$300 million.

Pursuant to the agreements with Brown Haynesville and Brown Southwest, EnCana operates the properties, receives all the revenue and pays all of the expenses associated with the properties. The arrangements with Brown Haynesville and Brown Southwest will be completed on March 24, 2009 and January 19, 2009, respectively, and the assets will be transferred to EnCana at that time. EnCana has determined that each relationship with Brown Haynesville and Brown Southwest represents an interest in a Variable Interest Entity ("VIE") and that EnCana is the primary beneficiary of the VIE. EnCana has consolidated Brown Haynesville and Brown Southwest from the dates of acquisition.

On November 20, 2007, EnCana acquired certain natural gas and land interests in Texas for approximately \$2.55 billion before closing adjustments. The purchase was facilitated by an unrelated party, Brown Kilgore Properties LLC ("Brown Kilgore"), which held the majority of the assets in trust for the Company in anticipation of a qualifying like kind exchange for U.S. tax purposes. The relationship with Brown Kilgore represented an interest in a VIE from November 20, 2007 to May 18, 2008. During this period, EnCana was the primary beneficiary of the VIE and consolidated Brown Kilgore. On May 18, 2008, when the arrangement with Brown Kilgore was completed, the assets were transferred to EnCana.

Additions to Goodwill

There were no additions to goodwill during 2008 or 2007.

Property, Plant and Equipment and Total Assets by Segment

As at December 31	Property, Plant and Equipment		Total Assets	
	2008	2007	2008	2007
Canada	\$ 17,105	\$ 19,519	\$ 23,441	\$ 27,014
USA	13,541	11,879	14,635	12,948
Downstream Refining	4,032	3,706	4,637	4,887
Market Optimization	140	171	429	478
Corporate & Other	606	590	4,105	1,647
Total	\$ 35,424	\$ 35,865	\$ 47,247	\$ 46,974

On February 9, 2007, EnCana announced that it had completed the next phase in the development of The Bow office project with the sale of project assets and has entered into a 25 year lease agreement with a third-party developer. As at December 31, 2008, Corporate and Other Property, Plant and Equipment and Total Assets include EnCana's accrual to date of \$252 million (2007 – \$147 million) related to this office project as an asset under construction.

On January 4, 2008, EnCana signed the contract for the design and construction of the Production Field Centre ("PFC") for the Deep Panuke project. As at December 31, 2008, Canada Property, Plant and Equipment and Total Assets include EnCana's accrual to date of \$199 million related to this offshore facility as an asset under construction.

Corresponding liabilities for these projects are included in Other Liabilities in the Consolidated Balance Sheet. There is no effect on the Company's net earnings or cash flows related to the capitalization of The Bow office project or the Deep Panuke PFC.

Property, Plant and Equipment, Goodwill And Total Assets by Geographic Region

As at December 31	Goodwill		Property, Plant and Equipment		Total Assets	
	2008	2007	2008	2007	2008	2007
Canada	\$ 1,953	\$ 2,420	\$ 17,790	\$ 20,126	\$ 27,726	\$ 28,402
United States	473	473	17,624	15,602	19,414	18,317
Other Countries	–	–	10	137	107	255
Total	\$ 2,426	\$ 2,893	\$ 35,424	\$ 35,865	\$ 47,247	\$ 46,974

Export Sales

Sales of natural gas, crude oil and NGLs produced or purchased in Canada delivered to customers outside of Canada were \$1,874 million (2007 – \$1,362 million; 2006 – \$1,814 million).

Major Customers

In connection with the marketing and sale of EnCana's own and purchased natural gas, crude oil and refined products for the year ended December 31, 2008, the Company had two customers (2007 – two; 2006 – one) which individually accounted for more than 10 percent of its consolidated revenues, net of royalties. Sales to these customers, major international integrated energy companies with a high quality investment grade credit rating, were approximately \$10,190 million (2007 – \$7,652 million; 2006 – \$1,951 million).

6. Discontinued Operations

As EnCana has focused its continuing operations on North American Upstream and Downstream Refining operations, a number of divestitures have been made which are accounted for as discontinued operations.

MIDSTREAM

The \$75 million gain on discontinuance in 2007 is the result of an expired clause included in the December 2005 sale of the Company's Midstream natural gas liquids processing operations. The clause provided potential market price support for the facilities and was accrued for in 2005.

During 2006, EnCana completed, in two separate transactions with a single purchaser, the sale of its natural gas storage operations in Canada and the United States. Total proceeds received were approximately \$1.5 billion and an after-tax gain on sale of \$829 million was recorded.

ECUADOR

On February 28, 2006, EnCana completed the sale of its Ecuador operations for proceeds of \$1.4 billion before indemnifications. A loss of \$279 million, including the impact of indemnifications, was recorded. Indemnifications are discussed further in this note.

Amounts recorded as depreciation, depletion and amortization in 2006 represent provisions which were recorded against the net book value of the Ecuador operations to recognize Management's best estimate of the difference between the selling price and the underlying accounting value of the related investments, as required by Canadian GAAP.

UNITED KINGDOM

On December 1, 2004, EnCana completed the sale of its 100 percent interest in EnCana (U.K.) Limited, holder of its U.K. operations, for net cash consideration of approximately \$2.1 billion. A gain on sale of approximately \$1.4 billion was recorded.

CONSOLIDATED STATEMENT OF EARNINGS

The following table presents the effect of the discontinued operations in the Consolidated Statement of Earnings:

	Midstream	Ecuador	United Kingdom	Consolidated Total			
For the years ended December 31	2007	2006	2006	2006	2008	2007	2006
Revenues, Net of Royalties⁽¹⁾	\$ -	\$ 482	\$ 200	\$ -	\$ -	\$ -	\$ 682
Expenses							
Production and mineral taxes	-	-	23	-	-	-	23
Transportation and selling	-	-	10	-	-	-	10
Operating	-	37	25	-	-	-	62
Purchased product	-	356	-	-	-	-	356
Depreciation, depletion and amortization	-	-	84	-	-	-	84
Administrative	-	-	-	-	-	-	-
Interest, net	-	-	(2)	-	-	-	(2)
Accretion of asset retirement obligation	-	-	-	-	-	-	-
Foreign exchange (gain) loss, net	-	4	1	(1)	-	-	4
(Gain) loss on discontinuance	(75)	(807)	279	-	-	(75)	(528)
	(75)	(410)	420	(1)	-	(75)	9
Net Earnings (Loss) Before Income Tax	75	892	(220)	1	-	75	673
Income tax expense (recovery)	-	17	59	(4)	-	-	72
Net Earnings (Loss) from Discontinued Operations	\$ 75	\$ 875	\$ (279)	\$ 5	\$ -	\$ 75	\$ 601
Net Earnings (Loss) from Discontinued Operations per Common Share							
Basic					\$ -	\$ 0.10	\$ 0.73
Diluted					\$ -	\$ 0.10	\$ 0.72

(1) Revenues, net of royalties in Ecuador for 2006 include realized losses of \$1 million related to derivative financial instruments.

There were no assets and liabilities related to discontinued operations as at December 31, 2008.

COMMITMENTS AND CONTINGENCIES

EnCana agreed to indemnify the purchaser of its Ecuador interests against losses that may arise in certain circumstances which are defined in the share sale agreements. The obligation to indemnify will arise should losses exceed amounts specified in the sale agreements and is limited to maximum amounts which are set forth in the share sale agreements.

During the second quarter of 2006, the Government of Ecuador seized the Block 15 assets, in relation to which EnCana previously held a 40 percent economic interest, from the operator which is an event requiring indemnification under the terms of EnCana's sale agreement with the purchaser. The purchaser requested payment and EnCana paid the maximum amount calculated in accordance with the terms of the agreements, approximately \$265 million. EnCana does not expect that any further significant indemnification payments relating to any other business matters addressed in the share sale agreements will be required to be made to the purchaser.

7. Divestitures

For the years ended December 31

	2008	2007	2006
Canadian Plains	\$ 39	\$ –	\$ 3
Canadian Foothills	400	213	56
Integrated Oil – Canada	8	–	–
Canada	447	213	59
USA	251	10	19
Market Optimization	–	–	244
Corporate & Other	206	258	367
	<hr/> \$ 904	<hr/> \$ 481	<hr/> \$ 689

Proceeds received on the sale of assets and investments in 2008 were \$904 million (2007 – \$481 million; 2006 – \$689 million). The significant items are described below.

CANADA

In 2008, the Company completed the divestiture of mature conventional oil and natural gas assets for proceeds of \$39 million (2007 – nil; 2006 – \$3 million) in Canadian Plains and \$400 million (2007 – \$213 million; 2006 – \$56 million) in Canadian Foothills.

In May 2007, the Company completed the sale of its assets in the Mackenzie Delta and Beaufort Sea for proceeds of \$159 million, which were credited to property, plant and equipment in the Canadian cost centre and reported in Canadian Foothills.

USA

In 2008, the Company completed the divestiture of mature conventional natural gas assets for proceeds of \$251 million (2007 – \$10 million; 2006 – \$19 million).

MARKET OPTIMIZATION

In February 2006, the Company sold its investment in Entrega Gas Pipeline LLC for approximately \$244 million which resulted in a gain on sale of \$17 million.

CORPORATE AND OTHER

In September 2008, the Company completed the sale of its interests in Brazil for net proceeds of \$164 million, before closing adjustments, resulting in a gain on sale of \$124 million. After recording income tax of \$25 million, EnCana recorded an after-tax gain of \$99 million.

In August 2007, the Company closed the sale of Australia assets for proceeds of \$31 million resulting in a gain on sale of \$30 million. After recording income tax of \$5 million, EnCana recorded an after-tax gain of \$25 million.

In February 2007, the Company sold The Bow office project assets for proceeds of approximately \$57 million, largely representing its investment at the date of sale. Refer to Note 5 for further discussion of The Bow office project assets.

In January 2007, the Company completed the sale of its interests in Chad, properties that were in the pre-production stage, for proceeds of \$208 million which resulted in a gain on sale of \$59 million.

In August 2006, EnCana completed the sale of its 50 percent interest in the Chinook heavy oil discovery offshore Brazil for approximately \$367 million which resulted in a gain on sale of \$304 million. After recording income tax of \$49 million, EnCana recorded an after-tax gain of \$255 million.

8. Interest, Net

For the years ended December 31	2008	2007	2006
Interest Expense – Long-Term Debt	\$ 556	\$ 460	\$ 366
Interest Expense – Other ⁽¹⁾	246	244	76
Interest Income ⁽¹⁾	(216)	(276)	(46)
	\$ 586	\$ 428	\$ 396

(1) In 2008 and 2007, Interest Expense – Other and Interest Income are primarily due to the Partnership Contribution Payable and Receivable, respectively. See Note 11.

9. Foreign Exchange (Gain) Loss, Net

For the years ended December 31	2008	2007	2006
Unrealized Foreign Exchange (Gain) Loss on:			
Translation of U.S. dollar debt issued from Canada	\$ 1,033	\$ (683)	\$ –
Translation of U.S. dollar partnership contribution receivable issued from Canada	(608)	617	–
Other Foreign Exchange (Gain) Loss	(2)	(98)	14
	\$ 423	\$ (164)	\$ 14

10. Income Taxes

The provision for income taxes is as follows:

For the years ended December 31	2008	2007	2006
Current			
Canada	\$ 548	\$ 900	\$ 764
United States	396	647	128
Other Countries	43	7	50
Total Current Tax	987	1,554	942
Future	1,646	(316)	1,407
Future Tax Rate Reductions	–	(301)	(457)
Total Future Tax	1,646	(617)	950
	\$ 2,633	\$ 937	\$ 1,892

Included in current tax for 2008 is \$25 million related to the sale of assets in Brazil (2007 – nil; 2006 – \$49 million).

The following table reconciles income taxes calculated at the Canadian statutory rate with the actual income taxes:

For the years ended December 31	2008	2007	2006
Net Earnings Before Income Tax	\$ 8,577	\$ 4,821	\$ 6,943
Canadian Statutory Rate	29.7%	32.3%	34.7%
Expected Income Tax	2,544	1,557	2,407
Effect on Taxes Resulting from:			
Non-deductible Canadian Crown payments	—	—	97
Canadian resource allowance	—	—	(16)
Statutory and other rate differences	167	76	(98)
Effect of tax rate changes	—	(301)	(457)
Effect of legislative changes	—	(179)	—
Non-taxable downstream partnership (income) loss	6	(70)	—
International financing	(309)	(62)	(59)
Foreign exchange (gains) losses not included in net earnings	49	—	—
Non-taxable capital (gains) losses	84	(124)	(1)
Other	92	40	19
	\$ 2,633	\$ 937	\$ 1,892
Effective Tax Rate	30.7%	19.4%	27.3%

The net future income tax liability is comprised of:

As at December 31	2008	2007
Future Tax Liabilities		
Property, plant and equipment in excess of tax values	\$ 5,372	\$ 5,400
Timing of partnership items	924	961
Risk management	958	89
Future Tax Assets		
Non-capital and net operating losses carried forward	(66)	(44)
Other	(269)	(198)
Net Future Income Tax Liability	\$ 6,919	\$ 6,208

The approximate amounts of tax pools available are as follows:

As at December 31	2008	2007
Canada	\$ 9,105	\$ 11,014
United States	8,516	7,101
	\$ 17,621	\$ 18,115

Included in the above tax pools are \$261 million (2007 – \$23 million) related to non-capital and net operating losses available for carry forward to reduce taxable income in future years. These losses expire between 2009 and 2027.

The current income tax provision includes amounts payable or recoverable in respect of Canadian partnership earnings included in the Consolidated Financial Statements for partnerships that have a year end that is after that of EnCana Corporation.

11. Partnership Contribution Receivable/Payable

PARTNERSHIP CONTRIBUTION RECEIVABLE

On January 2, 2007, upon the creation of the Integrated Oil joint venture, ConocoPhillips entered into a subscription agreement for a 50 percent interest in the upstream entity in exchange for a promissory note of \$7.5 billion. The note bears interest at a rate of 5.3 percent per annum. Equal payments of principal and interest are payable quarterly, with final payment due January 2, 2017. The current and long-term partnership contribution receivable shown in the Consolidated Balance Sheet represent EnCana's 50 percent share of this promissory note, net of payments to date.

Mandatory Receipts

	2009	2010	2011	2012	2013	Thereafter	Total
Partnership Contribution Receivable	\$ 313	\$ 330	\$ 347	\$ 366	\$ 386	\$ 1,405	\$ 3,147

PARTNERSHIP CONTRIBUTION PAYABLE

On January 2, 2007, upon the creation of the Integrated Oil joint venture, EnCana issued a promissory note to the downstream entity in the amount of \$7.5 billion in exchange for a 50 percent interest. The note bears interest at a rate of 6.0 percent per annum. Equal payments of principal and interest are payable quarterly, with final payment due January 2, 2017. The current and long-term partnership contribution payable amounts shown in the Consolidated Balance Sheet represent EnCana's 50 percent share of this promissory note, net of payments to date.

Mandatory Payments

	2009	2010	2011	2012	2013	Thereafter	Total
Partnership Contribution Payable	\$ 306	\$ 325	\$ 345	\$ 366	\$ 388	\$ 1,433	\$ 3,163

12. Inventories

As at December 31	2008	2007
Product		
Canada	\$ 46	\$ 65
USA	8	2
Downstream Refining	323	570
Market Optimization	127	180
Parts and Supplies	16	11
	\$ 520	\$ 828

As a result of a significant decline in commodity prices in the latter half of 2008, EnCana has written down its product inventory by \$152 million from cost to net realizable value.

The total amount of inventories recognized as an expense during the year, including the write-down, was \$8,749 million (2007 – \$5,752 million).

13. Property, Plant and Equipment, Net

As at December 31	2008			2007		
	Accumulated			Accumulated		
	Cost	DD&A ⁽¹⁾	Net	Cost	DD&A ⁽¹⁾	Net
Canada	\$ 34,660	\$ (17,555)	\$ 17,105	\$ 38,825	\$ (19,306)	\$ 19,519
USA	19,052	(5,511)	13,541	15,681	(3,802)	11,879
Downstream Refining	4,347	(315)	4,032	3,855	(149)	3,706
Market Optimization	220	(80)	140	253	(82)	171
Corporate & Other	1,074	(468)	606	1,207	(617)	590
	\$ 59,353	\$ (23,929)	\$ 35,424	\$ 59,821	\$ (23,956)	\$ 35,865

(1) Depreciation, depletion and amortization.

Canada and USA property, plant and equipment include internal costs directly related to exploration, development and construction activities of \$378 million (2007 – \$469 million). Costs classified as administrative expenses have not been capitalized as part of the capital expenditures.

Upstream costs in respect of significant unproved properties and major development projects are excluded from the country cost centre's depletable base. Downstream Refining assets not put into use are excluded from depreciable costs. At the end of the year these costs were:

As at December 31	2008	2007	2006
Canada	\$ 870	\$ 1,381	\$ 1,449
United States	3,399	1,852	956
Other Countries	10	137	263
Downstream Refining	488	139	–
	\$ 4,767	\$ 3,509	\$ 2,668

The costs excluded from depletable costs in Other Countries represent costs related to unproved properties incurred in cost centres that are considered to be in the pre-production stage. Currently, there are no proved reserves in these cost centres. All costs, net of any associated revenues, in these cost centres have been capitalized. Ultimate recoverability of these costs will be dependent upon the finding of proved oil and natural gas reserves. For the year ended December 31, 2008, the Company completed its impairment review of pre-production cost centres and determined that \$38 million of costs should be charged to depreciation, depletion and amortization in the Consolidated Statement of Earnings (2007 – \$68 million; 2006 – \$6 million).

Downstream Refining expenditures capitalized during the construction phase are not subject to depreciation until put in use and total \$488 million at December 31, 2008 (2007 – \$139 million).

The prices used in the ceiling test evaluation of the Company's natural gas and crude oil reserves at December 31, 2008 were:

	2009	2010	2011	2012	2013	Cumulative % Change to 2020
Natural Gas (\$/Mcft)						
Canada	6.60	6.57	6.37	6.28	6.32	4%
United States	6.54	6.74	6.81	6.72	6.73	–
Crude Oil (\$/barrel)						
Canada	49.51	48.46	47.50	47.02	46.70	(5)%
Natural Gas Liquids (\$/barrel)						
Canada	68.51	69.20	69.73	70.18	70.17	–
United States	61.65	61.37	61.46	61.14	60.93	(1)%

14. Investments and Other Assets

As at December 31	2008	2007
Prepaid Capital	\$ 520	\$ 383
Deferred Asset – Downstream Refining	134	159
Deferred Pension Plan and Savings Plan	59	50
Other	14	15
	\$ 727	\$ 607

15. Long-term Debt

As at December 31	Note	2008	2007
Canadian Dollar Denominated Debt			
Revolving credit and term loan borrowings	B	\$ 1,410	\$ 1,506
Unsecured notes	C	1,020	1,138
		2,430	2,644
U.S. Dollar Denominated Debt			
Revolving credit and term loan borrowings	D	247	495
Unsecured notes	E	6,350	6,421
		6,597	6,916
Increase in Value of Debt Acquired	F	49	66
Debt Discounts and Financing Costs	G	(71)	(83)
Current Portion of Long-Term Debt	H	(250)	(703)
		\$ 8,755	\$ 8,840

A) OVERVIEW

REVOLVING CREDIT AND TERM LOAN BORROWINGS

At December 31, 2008, EnCana Corporation had in place a revolving credit facility for C\$4.5 billion or its equivalent amount in U.S. dollars (\$3.7 billion). The facility, which matures in October 2012, is fully revolving for a period of up to five years. The facility is extendible from time to time, but not more than once per year, for a period not longer than five years plus 90 days from the date of the extension request, at the option of the lenders and upon notice from EnCana. The facility is unsecured and bears interest at the lenders' rates for Canadian prime, U.S. base rate, Bankers' Acceptances rates plus applicable margins, or at LIBOR plus applicable margins.

At December 31, 2008, one of EnCana's subsidiaries had in place a credit facility totaling \$600 million, of which \$565 million was accessible. One of the lenders under the facility, Lehman Brothers Bank, FSB, has ceased funding its \$35 million commitment as a result of the bankruptcy filing made by its affiliate, Lehman Brothers Holding Inc., on September 15, 2008. The facility, which matures in February 2013, is guaranteed by EnCana Corporation and is fully revolving for up to five years. The facility is extendible from time to time, but not more than once per year, for a period not longer than five years plus 90 days from the date of the extension request, at the option of the lenders and upon notice from the subsidiary. This facility bears interest at either the lenders' U.S. base rate or at LIBOR plus applicable margins.

Revolving credit and term loan borrowings include Bankers' Acceptances, Commercial Paper and LIBOR loans of \$1,657 million (2007 – \$2,001 million) maturing at various dates with a weighted average interest rate of 1.92 percent (2007 – 5.00 percent). These amounts are fully supported and Management expects that they will continue to be supported by revolving credit and term loan facilities that have no repayment requirements within the next year.

Standby fees paid in 2008 relating to revolving credit and term loan agreements were approximately \$4 million (2007 – \$4 million; 2006 – \$5 million).

UNSECURED NOTES

Unsecured notes include medium term notes and senior notes that are issued from time to time under trust indentures.

EnCana has in place a debt shelf prospectus for Canadian unsecured medium term notes in the amount of C\$2.0 billion which expires in June 2009. The shelf prospectus provides that debt securities in Canadian dollars or other foreign currencies may be issued from time to time in one or more series. Terms of the notes, including interest at either fixed or floating rates and maturity dates, are determined by reference to market conditions at the date of issue. At December 31, 2008, C\$1.25 billion (\$1.0 billion) of the shelf prospectus remained unutilized, the availability of which is dependent upon market conditions.

EnCana has in place a debt shelf prospectus for U.S. unsecured notes in the amount of \$4.0 billion under the multijurisdictional disclosure system ("MJDS"). The shelf prospectus provides that debt securities in U.S. dollars or other foreign currencies may be issued from time to time in one or more series. Terms of the notes, including interest at either fixed or floating rates and maturity dates, are determined by reference to market conditions at the date of issue. The shelf prospectus was filed in March 2008, expires in April 2010, and replaces the \$2.0 billion shelf prospectus which was fully utilized. At December 31, 2008, \$4.0 billion of the shelf prospectus remained unutilized, the availability of which is dependent upon market conditions.

EnCana has an indirect wholly owned subsidiary, EnCana Holdings Finance Corp., which, at December 31, 2007, had in place a debt shelf prospectus for U.S. unsecured notes in the amount of \$2 billion under the MJDS. The outstanding debt securities issued under this shelf prospectus are fully and unconditionally guaranteed by EnCana Corporation. EnCana has also obtained certain exemption orders from Canadian securities regulatory authorities that allowed the filing of certain financial and other information of EnCana to satisfy certain continuous disclosure obligations of EnCana Holdings Finance Corp. The shelf prospectus was renewed in 2006, expired in July 2008 and was not renewed.

B) CANADIAN REVOLVING CREDIT AND TERM LOAN BORROWINGS

	C\$ Principal Amount	2008	2007
Bankers' Acceptances	\$ 1,105	\$ 902	\$ 425
Commercial Paper	622	508	1,081
	\$ 1,727	\$ 1,410	\$ 1,506

C) CANADIAN UNSECURED NOTES

	C\$ Principal Amount	2008	2007
5.80% due June 2, 2008	\$ -	\$ -	\$ 126
3.60% due September 15, 2008	-	-	506
4.30% due March 12, 2012	500	408	506
5.80% due January 18, 2018	750	612	-
	\$ 1,250	\$ 1,020	\$ 1,138

D) U.S. REVOLVING CREDIT AND TERM LOAN BORROWINGS

	2008	2007
LIBOR	\$ 184	\$ 20
Commercial Paper	63	475
	\$ 247	\$ 495

E) U.S. UNSECURED NOTES

	2008	2007
5.80% due June 2, 2008	\$ -	\$ 71
4.60% due August 15, 2009	250	250
7.65% due September 15, 2010	200	200
6.30% due November 1, 2011	500	500
4.75% due October 15, 2013	500	500
5.80% due May 1, 2014	1,000	1,000
5.90% due December 1, 2017	700	700
8.125% due September 15, 2030	300	300
7.20% due November 1, 2031	350	350
7.375% due November 1, 2031	500	500
6.50% due August 15, 2034	750	750
6.625% due August 15, 2037	500	500
6.50% due February 1, 2038	800	800
	\$ 6,350	\$ 6,421

The 5.80% note due May 1, 2014 was issued by the Company's indirect wholly owned subsidiary, EnCana Holdings Finance Corp. This note is fully and unconditionally guaranteed by EnCana Corporation.

F) INCREASE IN VALUE OF DEBT ACQUIRED

Certain of the notes and debentures of the Company were acquired in business combinations and were accounted for at their fair value at the dates of acquisition. The difference between the fair value and the principal amount of the debt is being amortized over the remaining life of the outstanding debt acquired, approximately 20 years.

G) DEBT DISCOUNTS AND FINANCING COSTS

On January 1, 2007, upon adoption of the financial instruments standard, \$52 million of long-term debt transaction costs, premiums and discounts were reclassified from other assets to long-term debt. The costs capitalized within long-term debt are being amortized using the effective interest method. Previously, the Company deferred these costs within other assets and amortized them straight-line over the life of the related long-term debt. During 2008, \$5 million (2007 – \$25 million) in transaction costs and discounts have been capitalized within long-term debt relating to the issuance of Canadian and U.S. unsecured notes.

H) CURRENT PORTION OF LONG-TERM DEBT

	C\$ Principal Amount	2008		2007
5.80% due June 2, 2008	\$ –	\$ –	\$ 126	
5.80% due June 2, 2008	–	–	71	
3.60% due September 15, 2008	–	–	506	
4.60% due August 15, 2009	–	250	–	
	\$ –	\$ 250	\$ 703	

I) MANDATORY DEBT PAYMENTS

	C\$ Principal Amount	US\$ Principal Amount	Total US\$ Equivalent
2009	\$ –	\$ 250	\$ 250
2010	–	200	200
2011	–	500	500
2012	2,227	–	1,818
2013	–	747	747
Thereafter	750	4,900	5,512
Total	\$ 2,977	\$ 6,597	\$ 9,027

The amount due in 2009 excludes Bankers' Acceptances, Commercial Paper and LIBOR loans, which are fully supported by revolving credit and term loan facilities that have no repayment requirements within the next year. The revolving credit and term loan facilities are fully revolving for a period of up to five years. Based on the current maturity dates of the credit facilities, the payments are included in 2012 and 2013.

16. Asset Retirement Obligation

The following table presents the reconciliation of the beginning and ending aggregate carrying amount of the obligation associated with the retirement of oil and gas assets and refining facilities:

As at December 31	2008	2007
Asset Retirement Obligation, Beginning of Year	\$ 1,458	\$ 1,051
Liabilities Incurred	54	89
Liabilities Settled	(115)	(100)
Liabilities Divested	(38)	-
Change in Estimated Future Cash Flows	54	184
Accretion Expense	79	64
Foreign Currency Translation	(227)	163
Other	-	7
Asset Retirement Obligation, End of Year	\$ 1,265	\$ 1,458

The total undiscounted amount of estimated cash flows required to settle the obligation is \$6,569 million (2007 – \$7,395 million), which has been discounted using a weighted average credit-adjusted risk free rate of 6.04 percent (2007 – 5.85 percent). Most of these obligations are not expected to be paid for several years, or decades, in the future and will be funded from general Company resources at that time.

17. Share Capital

AUTHORIZED

The Company is authorized to issue an unlimited number of Common Shares, an unlimited number of First Preferred Shares and an unlimited number of Second Preferred Shares.

ISSUED AND OUTSTANDING

As at December 31	2008	2007		
	Number (millions)	Amount	Number (millions)	Amount
Common Shares Outstanding, Beginning of Year	750.2	\$ 4,479	777.9	\$ 4,587
Common Shares Issued under Option Plans	3.0	80	8.3	176
Stock-Based Compensation	–	11	–	17
Common Shares Purchased	(2.8)	(13)	(36.0)	(301)
Common Shares Outstanding, End of Year	750.4	\$ 4,557	750.2	\$ 4,479

NORMAL COURSE ISSUER BID

EnCana has received regulatory approval each year under Canadian securities laws to purchase Common Shares under seven consecutive Normal Course Issuer Bids ("Bids"). EnCana is entitled to purchase, for cancellation, up to approximately 75.0 million Common Shares under the renewed Bid which commenced on November 13, 2008 and terminates on November 12, 2009.

In 2008, the Company purchased 4.8 million Common Shares for total consideration of approximately \$326 million. Of the amount paid, \$29 million was charged to Share capital and \$297 million was charged to Retained earnings. Included in the Common Shares Purchased in 2008 are 2.0 million Common Shares distributed, valued at \$16 million, from the EnCana Employee Benefit Plan Trust that vested under EnCana's Performance Share Unit Plan (See Note 19). For these Common Shares distributed, there was a \$54 million adjustment to Retained earnings with a reduction to Paid in surplus of \$70 million.

In 2007, the Company purchased 38.9 million Common Shares for total consideration of approximately \$2,025 million. Of the amount paid, \$325 million was charged to Share capital and \$1,700 million was charged to Retained earnings. Included in the Common Shares Purchased in 2007 are 2.9 million Common Shares distributed, valued at \$24 million, from the EnCana Employee Benefit Plan Trust that vested under EnCana's Performance Share Unit Plan (See Note 19). For these Common Shares distributed, there was an \$82 million adjustment to Retained earnings with a reduction to Paid in surplus of \$106 million.

STOCK OPTIONS

EnCana has stock-based compensation plans that allow employees to purchase Common Shares of the Company. Option exercise prices approximate the market price for the Common Shares on the date the options were granted. Options granted under the plans are generally fully exercisable after three years and expire five years after the date granted. Options granted under predecessor and/or related company replacement plans expire up to 10 years from the date the options were granted. All options issued subsequent to December 31, 2003 have an associated Tandem Share Appreciation Right ("TSAR") attached to them (See Note 19).

ENCANA PLAN

Pursuant to the terms of a stock option plan, options may be granted to certain key employees to purchase EnCana Common Shares. Options granted on or after November 4, 1999 are exercisable at 30 percent of the number granted after one year, an additional 30 percent of the number granted after two years, are fully exercisable after three years and expire five years after the date granted. In addition, certain stock options granted since 2007 are performance based. The performance based stock options vest and expire under the same terms and service conditions as the underlying option, and vesting is subject to EnCana attaining prescribed performance relative to pre-determined key measures (See Note 19).

CANADIAN PACIFIC LIMITED REPLACEMENT PLAN

As part of the 2001 reorganization of Canadian Pacific Limited ("CPL"), EnCana's former parent company, CPL stock options were replaced with stock options granted by the Company in a manner that was consistent with the provisions of the CPL stock option plan. Under CPL's stock option plan, options were granted to certain key employees to purchase Common Shares of CPL at a price not less than the market value of the shares at the grant date. The options expire 10 years after the grant date and are all exercisable.

The following tables summarize the information related to options to purchase Common Shares that do not have a TSAR attached to them:

As at December 31	2008		2007		2006	
	Stock Options (millions)	Weighted Average Exercise Price (C\$)	Stock Options (millions)	Weighted Average Exercise Price (C\$)	Stock Options (millions)	Weighted Average Exercise Price (C\$)
Outstanding, Beginning of Year	3.4	21.82	11.8	23.17	20.7	23.36
Exercised	(2.9)	23.68	(8.3)	23.73	(8.6)	23.60
Forfeited	–	–	(0.1)	22.53	(0.3)	23.80
Outstanding, End of Year	0.5	11.62	3.4	21.82	11.8	23.17
Exercisable, End of Year	0.5	11.62	3.4	21.82	11.8	23.17

As at December 31, 2008	Outstanding Options			Exercisable Options		
	Number of Options Outstanding (millions)	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price (C\$)	Number of Options Outstanding (millions)	Weighted Average Exercise Price (C\$)	
Range of Exercise Price (C\$)						
11.00 to 14.50	0.5	0.9	11.62	0.5	11.62	

At December 31, 2008, there were 16.5 million Common Shares reserved for issuance under stock option plans (2007 – 12.2 million; 2006 – 20.7 million).

At December 31, 2007, the balance in Paid in surplus relates to stock-based compensation programs.

18. Capital Structure

The Company's capital structure is comprised of Shareholders' Equity plus Long-Term Debt. The Company's objectives when managing its capital structure are to:

- i) maintain financial flexibility to preserve EnCana's access to capital markets and its ability to meet its financial obligations; and
- ii) finance internally generated growth as well as potential acquisitions.

The Company monitors its capital structure and short-term financing requirements using non-GAAP financial metrics consisting of Debt to Capitalization and Debt to Adjusted Earnings Before Interest, Taxes, Depreciation and Amortization ("EBITDA"). These metrics are used to steward the Company's overall debt position as measures of the Company's overall financial strength.

To provide a more conservative measure of liquidity, the Company has changed its calculation of these metrics as follows: Net Debt to Capitalization has been changed to Debt to Capitalization and Net Debt to Adjusted EBITDA has been changed to Debt to Adjusted EBITDA. Debt is defined as the current and long-term portions of Long-Term Debt. Previously, Net Debt was defined as Long-Term Debt plus Current Liabilities less Current Assets. The Company believes this presentation is more comparable between periods by excluding the impact of unrealized mark-to-market accounting gains and losses on working capital.

EnCana targets a Debt to Capitalization ratio of between 30 and 40 percent. At December 31, 2008, EnCana's Debt to Capitalization ratio was 28 percent (December 31, 2007 – 32 percent) calculated as follows:

As at December 31	2008	2007
Debt	\$ 9,005	\$ 9,543
Total Shareholders' Equity	22,974	20,704
Total Capitalization	\$ 31,979	\$ 30,247
Debt to Capitalization ratio	28%	32%

Without giving effect to the change in calculation as described above, EnCana's Net Debt to Capitalization ratio would have been 23 percent at December 31, 2008 (December 31, 2007 – 34 percent).

EnCana targets a Debt to Adjusted EBITDA of 1.0 to 2.0 times. At December 31, 2008, Debt to Adjusted EBITDA was 0.7x (December 31, 2007 – 1.1x; December 31, 2006 – 0.7x) calculated on a trailing twelve-month basis as follows:

As at December 31	2008	2007	2006
Debt	\$ 9,005	\$ 9,543	\$ 6,834
Net Earnings from Continuing Operations	5,944	3,884	5,051
Add (deduct):			
Interest, net	586	428	396
Income tax expense	2,633	937	1,892
Depreciation, depletion and amortization	4,223	3,816	3,112
Accretion of asset retirement obligation	79	64	50
Foreign exchange (gain) loss, net	423	(164)	14
(Gain) loss on divestitures	(140)	(65)	(323)
Adjusted EBITDA	\$ 13,748	\$ 8,900	\$ 10,192
Debt to Adjusted EBITDA	0.7x	1.1x	0.7x

Without giving effect to the change in calculation as described above, EnCana's Net Debt to Adjusted EBITDA would have been 0.5x at December 31, 2008 (December 31, 2007 – 1.2x; December 31, 2006 – 0.6x).

EnCana has a long-standing practice of maintaining capital discipline, managing its capital structure and adjusting its capital structure according to market conditions to maintain flexibility while achieving the objectives stated above. To manage the capital structure, the Company may adjust capital spending, adjust dividends paid to shareholders, purchase shares for cancellation pursuant to normal course issuer bids, issue new shares, issue new debt or repay existing debt.

The Company's capital management objectives, evaluation measures, definitions and targets have remained unchanged over the periods presented, except as noted above. EnCana is subject to certain financial covenants in its credit facility agreements and is in compliance with all financial covenants.

19. Compensation Plans

A) PENSIONS AND OTHER POST-EMPLOYMENT BENEFITS

The Company sponsors defined benefit and defined contribution plans, providing pension and other post-employment benefits ("OPEB") to its employees.

The Company is required to file an actuarial valuation of its pension plans with the provincial regulator at least every three years. The most recent filing was dated December 31, 2005, and the Company is required, by June 30, 2009, to file an actuarial valuation as at December 31, 2008.

Information related to defined benefit pension and other post-employment benefit plans, based on actuarial estimations as at December 31, 2008 is as follows:

ACCRUED BENEFIT OBLIGATION

	Pension Benefits			OPEB		
	2008	2007		2008	2007	
As at December 31						
Accrued Benefit Obligation, Beginning of Year	\$ 357	\$ 308		\$ 53	\$ 45	
Current service cost	7	8		8	8	
Interest cost	18	16		3	3	
Benefits paid	(17)	(17)		(1)	(1)	
Actuarial (gain) loss	(36)	(14)		(3)	(5)	
Contributions	1	1		—	—	
Foreign exchange (gain) loss	(67)	55		(5)	3	
Accrued Benefit Obligation, End of Year	\$ 263	\$ 357		\$ 55	\$ 53	

PLAN ASSETS

	Pension Benefits			OPEB		
	2008	2007		2008	2007	
As at December 31						
Fair Value of Plan Assets, Beginning of Year	\$ 355	\$ 304		—	\$ —	—
Actual gain (loss) on return of plan assets	(53)	5		—	—	—
Employer contributions	8	8		—	—	—
Employees' contributions	1	1		—	—	—
Benefits paid	(17)	(17)		—	—	—
Foreign exchange gain (loss)	(61)	54		—	—	—
Fair Value of Plan Assets, End of Year	\$ 233	\$ 355		\$ —	\$ —	—

ACCRUED BENEFIT ASSET (LIABILITY)

	Pension Benefits			OPEB	
	2008	2007		2008	2007
As at December 31					
Funded Status – Plan Assets (less) than Benefit Obligation	\$ (30)	\$ (2)	\$ (55)	\$ (53)	
Amounts Not Recognized:					
Unamortized net actuarial (gain) loss	74	59	(5)	(3)	
Unamortized past service cost	4	6	1	1	
Net transitional asset (liability)	—	(3)	10	12	
Accrued Benefit Asset (Liability)	\$ 48	\$ 60	\$ (49)	\$ (43)	

	Pension Benefits			OPEB	
	2008	2007		2008	2007
As at December 31					
Prepaid Benefit Cost	\$ 48	\$ 60	\$ —	\$ —	
Accrued Benefit Cost	—	—	(49)	(43)	
Net Amount Recognized	\$ 48	\$ 60	\$ (49)	\$ (43)	

The Company's OPEB plans are funded on an as required basis.

The weighted average assumptions used to determine benefit obligations are as follows:

	Pension Benefits			OPEB	
	2008	2007		2008	2007
As at December 31					
Discount Rate	6.25%	5.25%	6.25%	5.50%	
Rate of Compensation Increase	4.16%	4.28%	6.00%	5.77%	

The weighted average assumptions used to determine periodic expense are as follows:

	Pension Benefits			OPEB	
	2008	2007		2008	2007
For the years ended December 31					
Discount Rate	5.25%	5.00%	5.50%	5.38%	
Expected Long-Term Rate of Return on Plan Assets:					
Registered pension plans	6.75%	6.75%	n/a	n/a	
Supplemental pension plans	3.375%	3.375%	n/a	n/a	
Rate of Compensation Increase	4.28%	4.34%	6.00%	5.77%	

The periodic expense for benefits is as follows:

For the years ended December 31	Pension Benefits			OPEB		
	2008	2007	2006	2008	2007	2006
Current Service Cost	\$ 7	\$ 8	\$ 9	\$ 8	\$ 8	\$ 7
Interest Cost	18	16	15	3	3	2
Actual (Gain) Loss on Return of Plan Assets	53	(5)	(27)	–	–	–
Actuarial (Gain) Loss on Accrued Benefit Obligation	(36)	(14)	6	(3)	(5)	(2)
Difference Between Actual and:						
Expected return on plan assets	(72)	(14)	11	–	–	–
Recognized actuarial gain (loss)	40	18	–	3	5	2
Difference Between Amortization of Past Service Costs and Actual Plan Amendments	2	2	2	–	–	–
Amortization of Transitional Assets (Obligation)	(3)	(3)	(3)	1	1	2
Defined Benefit Plans Expense	\$ 9	\$ 8	\$ 13	\$ 12	\$ 12	\$ 11
Defined Contribution Plans Expense	\$ 44	\$ 34	\$ 28	\$ –	\$ –	\$ –
Total Benefit Plans Expense	\$ 53	\$ 42	\$ 41	\$ 12	\$ 12	\$ 11

The average remaining service period of the active employees covered by the defined benefit pension plan is five years. The average remaining service period of the active employees covered by the OPEB plan is 11 years.

Assumed health care cost trend rates are as follows:

As at December 31	2008	2007
Health Care Cost Trend Rate for Next Year	9.50%	10.50%
Rate that the Trend Rate Gradually Trends To	5.00%	5.00%
Year that the Trend Rate Reaches the Rate which it is Expected to Remain At	2017	2016

Assumed health care cost trend rates have an effect on the amounts reported for the OPEB plans. A one percentage point change in assumed health care cost trend rates would have the following effects:

	One Percentage Point Increase		One Percentage Point Decrease	
Effect on Total of Service and Interest Cost	\$ 1		\$ (1)	
Effect on Post-Retirement Benefit Obligation	\$ 5		\$ (4)	

The Company's pension plan asset allocations are as follows:

Asset Category	Target Allocation %		% of Plan Assets at December 31		Expected Long-Term Rate of Return
	Normal	Range	2008	2007	
Domestic Equity	35	25-45	34	39	
Foreign Equity	30	20-40	25	27	
Bonds	30	20-40	33	27	
Real Estate and Other	5	0-20	8	7	
Total	100		100	100	6.75%

The expected rate of return on plan assets is based on historical and projected rates of return for each asset class in the plan investment portfolio. The objective of the asset allocation policy is to manage the funded status of the plan at an appropriate level of risk, giving consideration to the security of the assets and the potential volatility of market returns and the resulting effect on both contribution requirements and pension expense. The long-term return is expected to achieve or exceed the return from a composite benchmark comprised of passive investments in appropriate market indices. The Supplemental Pension Plan is funded through a retirement compensation arrangement and is subject to the applicable Canada Revenue Agency regulations.

The asset allocation structure is subject to diversification requirements and constraints which reduce risk by limiting exposure to individual equity investment, credit rating categories and foreign currency exposure.

The Company's contributions to the pension plans are subject to the results of the actuarial valuation and direction by the Human Resources and Compensation Committee. Contributions by the participants to the pension and other benefits plans were \$1 million for the year ended December 31, 2008 (2007 – \$1 million; 2006 – \$1 million).

Estimated future payment of pension and other benefits are as follows:

	Pension Benefits	OPEB
2009	\$ 17	\$ 2
2010	18	2
2011	19	3
2012	20	3
2013	21	4
2014 – 2018	120	28
Total	\$ 215	\$ 42

B) TANDEM SHARE APPRECIATION RIGHTS

Subsequent to December 31, 2003, all options to purchase Common Shares issued under the share option plans described in Note 17 have an associated TSAR attached to them whereby the option holder has the right to receive a cash payment equal to the excess of the market price of EnCana's Common Shares at the time of exercise over the exercise price of the right in lieu of exercising the option. The TSARs vest and expire under the same terms and conditions as the underlying option.

The following tables summarize information related to the TSARs:

As at December 31		2008		2007
	Outstanding TSARs	Weighted Average Exercise Price	Outstanding TSARs	Weighted Average Exercise Price
Canadian Dollar Denominated (C\$)				
Outstanding, Beginning of Year	18,854,141	48.44	17,276,191	44.99
Granted	4,420,272	70.11	4,814,338	57.70
Exercised – SARs	(3,173,443)	43.68	(2,020,357)	41.20
Exercised – Options	(82,936)	42.00	(12,235)	35.04
Forfeited	(606,095)	55.27	(1,203,796)	50.02
Outstanding, End of Year	19,411,939	53.97	18,854,141	48.44
Exercisable, End of Year	8,452,111	46.45	5,267,550	43.18

As at December 31, 2008		Outstanding TSARs		Exercisable TSARs	
Range of Exercise Price (C\$)	Number of TSARs	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price	Number of TSARs	Weighted Average Exercise Price
20.00 to 29.99	156,873	0.37	27.66	156,873	27.66
30.00 to 39.99	2,790,012	1.12	38.22	2,789,912	38.22
40.00 to 49.99	6,904,479	2.12	48.17	3,652,139	48.10
50.00 to 59.99	4,442,058	2.90	55.92	1,536,897	55.73
60.00 to 69.99	4,548,147	3.94	68.24	302,205	63.99
70.00 to 79.99	355,420	4.37	74.13	14,085	70.14
80.00 to 89.99	128,650	4.41	85.50	–	–
90.00 to 99.99	86,300	4.45	92.94	–	–
	19,411,939	2.63	53.97	8,452,111	46.45

During the year, the Company recorded a reduction of compensation costs of \$47 million related to the outstanding TSARs (2007 – compensation costs of \$225 million; 2006 – compensation costs of \$52 million).

C) PERFORMANCE TANDEM SHARE APPRECIATION RIGHTS

Beginning in 2007, under the terms of the existing Employee Stock Option Plan, EnCana granted Performance Tandem Share Appreciation Rights ("Performance TSARs") under which the employee has the right to receive a cash payment equal to the excess of the market price of EnCana Common Shares at the time of exercise over the grant price. Performance TSARs vest and expire under the same terms and service conditions as the underlying option, and vesting is subject to EnCana attaining prescribed performance relative to key pre-determined measures. Performance TSARs that do not vest when eligible are forfeited.

The following tables summarize information related to the Performance TSARs:

As at December 31		2008		2007
	Outstanding Performance TSARs	Weighted Average Exercise Price	Outstanding Performance TSARs	Weighted Average Exercise Price
Canadian Dollar Denominated (C\$)				
Outstanding, Beginning of Year	6,930,925	56.09	—	—
Granted	7,058,538	69.40	7,275,575	56.09
Exercised – SARs	(287,299)	56.09	—	—
Exercised – Options	(5,123)	56.09	—	—
Forfeited	(717,316)	59.65	(344,650)	56.09
Outstanding, End of Year	12,979,725	63.13	6,930,925	56.09
Exercisable, End of Year	1,461,276	56.09	—	—

As at December 31, 2008		Outstanding Performance TSARs		Exercisable Performance TSARs	
Range of Exercise Price (C\$)	Number of TSARs	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price	Number of TSARs	Weighted Average Exercise Price
50.00 to 59.99	6,113,087	3.08	56.09	1,461,276	56.09
60.00 to 69.99	6,866,638	4.08	69.40	—	—
	12,979,725	3.55	63.13	1,461,276	56.09

During the year, EnCana recorded a reduction of compensation costs of \$6 million related to the outstanding Performance TSARs (2007 – compensation costs of \$21 million).

D) SHARE APPRECIATION RIGHTS

EnCana has a program whereby employees may be granted Share Appreciation Rights ("SARs") which entitle the employee to receive a cash payment equal to the excess of the market price of EnCana's Common Shares at the time of exercise over the exercise price of the right. SARs granted during 2008 are exercisable at 30 percent of the number granted after one year, an additional 30 percent of the number granted after two years and are fully exercisable after three years and expire five years after the grant date.

The following tables summarize information related to the SARs:

As at December 31	2008	2007		
	Outstanding SARs	Weighted Average Exercise Price	Outstanding SARs	Weighted Average Exercise Price
Canadian Dollar Denominated (C\$)				
Outstanding, Beginning of Year	-	-	-	-
Granted	1,314,115	72.07	-	-
Forfeited	(29,050)	69.42	-	-
Outstanding, End of Year	1,285,065	72.13	-	-
Exercisable, End of Year	-	-	-	-
U.S. Dollar Denominated (US\$)				
Outstanding, Beginning of Year	-	-	2,088	14.21
Exercised	-	-	(2,088)	14.21
Outstanding, End of Year	-	-	-	-
Exercisable, End of Year	-	-	-	-

As at December 31, 2008	/	Outstanding SARs		Exercisable SARs		
Range of Exercise Price (C\$)		Number of SARs	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price	Number of SARs	Weighted Average Exercise Price
40.00 to 49.99		20,400	4.79	45.74	-	-
50.00 to 59.99		28,800	4.81	57.79	-	-
60.00 to 69.99		815,065	4.09	69.37	-	-
70.00 to 79.99		260,550	4.65	73.40	-	-
80.00 to 89.99		87,150	4.44	87.05	-	-
90.00 to 99.99		73,100	4.42	93.65	-	-
		1,285,065	4.16	72.13	-	-

During the year, the Company has not recorded any compensation costs related to the outstanding SARs (2007 – nil; 2006 – reduction of compensation costs of \$1 million).

E) PERFORMANCE SHARE APPRECIATION RIGHTS

In 2008, EnCana granted Performance Share Appreciation Rights ("Performance SARs") to certain employees which entitles the employee to receive a cash payment equal to the excess of the market price of EnCana's Common Shares at the time of exercise over the grant price. Performance SARs vest and expire under the same terms and service conditions as SARs and are also subject to EnCana attaining prescribed performance relative to pre-determined key measures. Performance SARs that do not vest when eligible are forfeited.

The following tables summarize information related to the Performance SARS:

As at December 31	2008		2007	
	Outstanding Performance SARs	Weighted Average Exercise Price	Outstanding Performance SARs	Weighted Average Exercise Price
Canadian Dollar Denominated (C\$)				
Outstanding, Beginning of Year	—	—	—	—
Granted	1,677,030	69.40	—	—
Forfeited	(56,100)	69.40	—	—
Outstanding, End of Year	1,620,930	69.40	—	—
Exercisable, End of Year	—	—	—	—

As at December 31, 2008	Outstanding Performance SARs			Exercisable Performance SARs		
	Number of SARs	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price	Number of SARs	Weighted Average Exercise Price	
Range of Exercise Price (C\$)						
60.00 to 69.99	1,620,930	4.08	69.40	—	—	—

During the year, the Company has not recorded any compensation costs related to the outstanding Performance SARs (2007 – nil).

F) DEFERRED SHARE UNITS

The Company has in place a program whereby Directors and certain key employees are issued Deferred Share Units ("DSUs"), which are equivalent in value to a Common Share of the Company. DSUs granted to Directors vest immediately. DSUs expire on December 15th of the year following the Director's resignation or employee's termination.

The following table summarizes information related to the DSUs:

As at December 31	2008	2007
	Outstanding DSUs	Outstanding DSUs
Canadian Dollar Denominated		
Outstanding, Beginning of Year	589,174	866,577
Granted	85,792	79,168
Units, in Lieu of Dividends	15,883	9,314
Redeemed	(34,008)	(365,885)
Outstanding, End of Year	656,841	589,174

During the year, the Company recorded compensation costs of \$2 million related to the outstanding DSUs (2007 – \$14 million; 2006 – \$5 million).

G) PERFORMANCE SHARE UNITS

Performance Share Units ("PSUs") were granted in 2003, 2004 and 2005 and entitled employees to receive upon vesting, either a Common Share of EnCana or a cash payment equal to the value of one Common Share of EnCana, depending upon the terms of the PSUs granted. PSUs vested over a three year period from the date granted. If EnCana's performance was at or above a specified level compared to a pre-determined peer group, payments ranged from one half to two times the PSU. At December 31, 2008, there are no PSUs outstanding.

PSUs granted in 2003 were paid out in cash at 75 percent of the number granted. PSUs granted in 2004 were paid out in Common Shares at 100 percent of the number granted. PSUs granted in 2005 were paid out in Common Shares at 125 percent of the number granted.

The following table summarizes information related to the PSUs:

As at December 31	2008		2007	
	Outstanding PSUs	Average Share Price	Outstanding PSUs	Average Share Price
Canadian Dollar Denominated (C\$)				
Outstanding, Beginning of Year	1,685,036	38.79	4,766,329	31.24
Granted	408,686	70.77	23,097	62.84
Distributed	(2,042,541)	45.34	(2,937,491)	26.98
Forfeited	(51,181)	38.32	(166,899)	34.38
Outstanding, End of Year	–	–	1,685,036	38.79

During the year, the Company recorded compensation costs of \$1 million related to the outstanding PSUs (2007 – \$43 million; 2006 – \$27 million).

20. Financial Instruments and Risk Management

EnCana's financial assets and liabilities are comprised of cash and cash equivalents, accounts receivable and accrued revenues, accounts payable and accrued liabilities, the partnership contribution receivable and payable, risk management assets and liabilities, and long-term debt. Risk management assets and liabilities arise from the use of derivative financial instruments. Fair values of financial assets and liabilities, summarized information related to risk management positions, and discussion of risks associated with financial assets and liabilities are presented as follows.

A) FAIR VALUE OF FINANCIAL ASSETS AND LIABILITIES

The fair values of cash and cash equivalents, accounts receivable and accrued revenues, and accounts payable and accrued liabilities approximate their carrying amount due to the short-term maturity of those instruments.

The fair values of the partnership contribution receivable and partnership contribution payable approximate their carrying amount due to the specific nature of these instruments in relation to the creation of the integrated oil joint venture. Further information about these notes is disclosed in Note 11.

Risk management assets and liabilities are recorded at their estimated fair value based on the mark-to-market method of accounting, using quoted market prices or, in their absence, third-party market indications and forecasts.

Long-term debt is carried at amortized cost using the effective interest method of amortization. The estimated fair values of long-term borrowings have been determined based on market information where available, or by discounting future payments of interest and principal at estimated interest rates expected to be available to the Company at period end.

The fair value of financial assets and liabilities were as follows:

As at December 31	2008		2007	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Financial Assets				
Held-for-trading:				
Cash and cash equivalents	\$ 383	\$ 383	\$ 553	\$ 553
Risk management assets ⁽¹⁾	3,052	3,052	403	403
Loans and Receivables:				
Accounts receivable and accrued revenues	1,568	1,568	2,381	2,381
Partnership contribution receivable ⁽¹⁾	3,147	3,147	3,444	3,444
Financial Liabilities				
Held-for-trading:				
Risk management liabilities ⁽¹⁾	\$ 50	\$ 50	\$ 236	\$ 236
Other Financial Liabilities:				
Accounts payable and accrued liabilities	2,871	2,871	3,982	3,982
Long-term debt ⁽¹⁾	9,005	8,242	9,543	9,763
Partnership contribution payable ⁽¹⁾	3,163	3,163	3,451	3,451

(1) Including current portion.

B) RISK MANAGEMENT ASSETS AND LIABILITIES

NET RISK MANAGEMENT POSITION

As at December 31	2008	2007
Risk Management		
Current asset	\$ 2,818	\$ 385
Long-term asset	234	18
	3,052	403
Risk Management		
Current liability	43	207
Long-term liability	7	29
	50	236
Net Risk Management Asset (Liability)	\$ 3,002	\$ 167

SUMMARY OF UNREALIZED RISK MANAGEMENT POSITIONS

As at December 31	2008	2007				
	Risk Management			Risk Management		
	Asset	Liability	Net	Asset	Liability	Net
Commodity Prices						
Natural Gas	\$ 2,941	\$ 10	\$ 2,931	\$ 375	\$ 29	\$ 346
Crude Oil	92	40	52	6	205	(199)
Power	19	—	19	19	—	19
Interest Rates	—	—	—	2	—	2
Credit	—	—	—	1	2	(1)
Total Fair Value	\$ 3,052	\$ 50	\$ 3,002	\$ 403	\$ 236	\$ 167

NET FAIR VALUE METHODOLOGIES USED TO CALCULATE UNREALIZED RISK MANAGEMENT POSITIONS

As at December 31	2008	2007
Prices actively quoted	\$ 2,055	\$ 105
Prices sourced from observable data or market corroboration	947	62
Total Fair Value	\$ 3,002	\$ 167

Prices actively quoted refers to the fair value of contracts valued using quoted prices in an active market. Prices sourced from observable data or market corroboration refers to the fair value of contracts valued in part using active quotes and in part using observable, market-corroborated data.

NET FAIR VALUE OF COMMODITY PRICE POSITIONS AT DECEMBER 31, 2008

	Notional Volumes	Term	Average Price	Fair Value
Natural Gas Contracts				
Fixed Price Contracts				
NYMEX Fixed Price	1,648 MMcf/d	2009	9.28 US\$/Mcf	\$ 1,981
NYMEX Fixed Price	35 MMcf/d	2010	9.21 US\$/Mcf	23
Purchased Options				
NYMEX Call Options	(150) MMcf/d	2009	11.67 US\$/Mcf	(22)
NYMEX Put Options	516 MMcf/d	2009	9.10 US\$/Mcf	536
Basis Contracts				
Canada	71 MMcf/d	2009		—
United States	917 MMcf/d	2009		111
Canada and United States ⁽¹⁾		2010-2013		193
				2,822
Other Financial Positions ⁽²⁾				(1)
Total Unrealized Gain on Financial Contracts				2,821
Premiums Paid on Unexpired Options				110
Natural Gas Fair Value Position				\$ 2,931
Crude Oil Contracts ⁽³⁾				
Crude Oil Fair Value Position				\$ 52
Power Purchase Contracts				
Power Fair Value Position				\$ 19

(1) EnCana has entered into swaps to protect against widening natural gas price differentials between production areas, including Canada, the U.S. Rockies and Texas, and various sales points. These basis swaps are priced using both fixed prices and basis prices determined as a percentage of NYMEX.

(2) Other financial positions are part of the ongoing operations of the Company's proprietary production management.

(3) The Crude Oil financial positions are part of the ongoing operations of the Company's proprietary production and condensate management and its share of downstream refining positions.

**NET EARNINGS IMPACT OF REALIZED AND UNREALIZED
GAINS (LOSSES) ON RISK MANAGEMENT POSITIONS**

	Realized Gain (Loss)		
For the years ended December 31	2008	2007	2006
Revenues, Net of Royalties	\$ (309)	\$ 1,601	\$ 393
Operating Expenses and Other	28	3	5
Gain (Loss) on Risk Management – Continuing Operations	(281)	1,604	398
Gain (Loss) on Risk Management – Discontinued Operations	–	–	12
	\$ (281)	\$ 1,604	\$ 410

	Unrealized Gain (Loss)		
For the years ended December 31	2008	2007	2006
Revenues, Net of Royalties	\$ 2,717	\$ (1,239)	\$ 2,050
Operating Expenses and Other	12	4	10
Gain (Loss) on Risk Management – Continuing Operations	2,729	(1,235)	2,060
Gain (Loss) on Risk Management – Discontinued Operations	–	–	20
	\$ 2,729	\$ (1,235)	\$ 2,080

**RECONCILIATION OF UNREALIZED RISK MANAGEMENT
POSITIONS FROM JANUARY 1 TO DECEMBER 31, 2008**

	2008	2007	2006
	Fair Value	Total Unrealized Gain (Loss)	Total Unrealized Gain (Loss)
Fair Value of Contracts, Beginning of Year	\$ 167		
Change in Fair Value of Contracts in Place at Beginning of Year and Contracts Entered into During the Year	2,448	\$ 2,448	\$ 353
Fair Value of Contracts in Place at Transition that Expired During the Year	–	–	16
Foreign Exchange Gain (Loss) on Canadian Dollar Contracts	(4)	–	–
Fair Value of Contracts Realized During the Year	281	281	(1,604)
Fair Value of Contracts Outstanding	\$ 2,892	\$ 2,729	\$ (1,235)
Premiums Paid on Unexpired Options	110		
Fair Value of Contracts and Premiums Paid, End of Year	\$ 3,002		

COMMODITY PRICE SENSITIVITIES

The following table summarizes the sensitivity of the fair value of the Company's risk management positions to fluctuations in commodity prices, with all other variables held constant. When assessing the potential impact of these commodity price changes, the Company believes 10 percent volatility is a reasonable measure. Fluctuations in commodity prices could have resulted in unrealized gains (losses) impacting net earnings as at December 31, 2008 as follows:

	Favourable 10% Change	Unfavourable 10% Change
Natural gas price	\$ 424	\$ (418)
Crude oil price	7	(7)
Power price	9	(9)

C) RISKS ASSOCIATED WITH FINANCIAL ASSETS AND LIABILITIES

The Company is exposed to financial risks arising from its financial assets and liabilities. Financial risks include market risks (such as commodity prices, foreign exchange and interest rates), credit risk and liquidity risk. The fair value or future cash flows of financial assets or liabilities may fluctuate due to movement in market prices and the exposure to credit and liquidity risks.

COMMODITY PRICE RISK

Commodity price risk arises from the effect that fluctuations of future commodity prices may have on the fair value or future cash flows of financial assets and liabilities. To partially mitigate exposure to commodity price risk, the Company has entered into various financial derivative instruments. The use of these derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors. The Company's policy is to not use derivative financial instruments for speculative purposes.

Natural Gas – To partially mitigate the natural gas commodity price risk, the Company has entered into option contracts and swaps, which fix the NYMEX prices. To help protect against widening natural gas price differentials in various production areas, EnCana has entered into swaps to manage the price differentials between these production areas and various sales points.

Crude Oil – The Company has partially mitigated its exposure to the commodity price risk on its condensate supply with fixed price swaps.

Power – The Company has in place two Canadian dollar denominated derivative contracts, which commenced January 1, 2007 for a period of 11 years, to manage its electricity consumption costs.

CREDIT RISK

Credit risk arises from the potential the Company may incur a loss if a counterparty to a financial instrument fails to meet its obligation in accordance with agreed terms. This credit risk exposure is mitigated through the use of Board-approved credit policies governing the Company's credit portfolio and with credit practices that limit transactions according to counterparties' credit quality. All foreign currency agreements are with major financial institutions in Canada and the United States or with counterparties having investment grade credit ratings. A substantial portion of the Company's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks. As at December 31, 2008, over 95 percent of EnCana's accounts receivable and financial derivative credit exposures are with investment grade counterparties.

At December 31, 2008, EnCana had two counterparties whose net settlement position individually account for more than 10 percent of the fair value of the outstanding in-the-money net financial instrument contracts by counterparty. The maximum credit risk exposure associated with accounts receivable and accrued revenues, risk management assets and the partnership contribution receivable is the total carrying value.

LIQUIDITY RISK

Liquidity risk is the risk the Company will encounter difficulties in meeting a demand to fund its financial liabilities as they come due. The Company manages its liquidity risk through cash and debt management. As disclosed in Note 18, EnCana targets a Debt to Capitalization ratio between 30 and 40 percent and a Debt to Adjusted EBITDA of 1.0 to 2.0 times to steward the Company's overall debt position.

In managing liquidity risk, the Company has access to a wide range of funding at competitive rates through commercial paper, capital markets and banks. As at December 31, 2008, EnCana had available unused committed bank credit facilities in the amount of \$2.6 billion and unused capacity under shelf prospectuses, the availability of which is dependent on market conditions, for \$5.0 billion. The Company believes it has sufficient funding through the use of these facilities to meet foreseeable borrowing requirements.

EnCana maintains investment grade credit ratings on its senior unsecured debt. On May 12, 2008, following the announcement of the proposed Arrangement (See Note 3), Standard & Poor's Ratings Service assigned a rating of A- and placed the Company on "CreditWatch Negative", DBRS Limited assigned a rating of A(low) and placed the Company "Under Review with Developing Implications", and Moody's Investors Service assigned a rating of Baa2 and changed the outlook to "Stable" from "Positive".

The timing of cash outflows relating to financial liabilities are outlined in the table below:

	Less than 1 Year	1 – 3 Years	4 – 5 Years	Thereafter	Total
Accounts Payable and Accrued Liabilities	\$ 2,871	\$ –	\$ –	\$ –	\$ 2,871
Risk Management Liabilities	43	7	–	–	50
Long-Term Debt ⁽¹⁾	727	1,589	3,344	10,392	16,052
Partnership Contribution Payable ⁽¹⁾	489	978	978	1,588	4,033

(1) Principal and interest, including current portion.

Included in EnCana's total long-term debt obligations of \$16,052 million at December 31, 2008 are \$1,657 million in principal obligations related to Bankers' Acceptances, Commercial Paper and LIBOR loans. These amounts are fully supported and Management expects that they will continue to be supported by revolving credit and term loan facilities that have no repayment requirements within the next year. The revolving credit and term loan facilities are fully revolving for a period of up to five years. Based on the current maturity dates of the credit facilities, these amounts are included in cash outflows for the period disclosed as 4 – 5 Years. Further information on Long-term Debt is contained in Note 15.

FOREIGN EXCHANGE RISK

Foreign exchange risk arises from changes in foreign exchange rates that may affect the fair value or future cash flows of the Company's financial assets or liabilities. As EnCana operates primarily in North America, fluctuations in the exchange rate between the U.S./Canadian dollar can have a significant effect on the Company's reported results. EnCana's functional currency is Canadian dollars, however, the Company reports its results in U.S. dollars as most of its revenue is closely tied to the U.S. dollar and to facilitate a more direct comparison to other North American oil and gas companies. As the effects of foreign exchange fluctuations are embedded in the Company's results, the total effect of foreign exchange fluctuations are not separately identifiable.

To mitigate the exposure to the fluctuating U.S./Canadian exchange rate, EnCana maintains a mix of both U.S. dollar and Canadian dollar debt.

As disclosed in Note 9, EnCana's foreign exchange (gain) loss is primarily comprised of unrealized foreign exchange gains and losses on the translation of U.S. dollar debt issued from Canada and the translation of the U.S. dollar partnership contribution receivable issued from Canada. At December 31, 2008, EnCana had \$5,350 million in U.S. dollar debt issued from Canada (\$5,421 million at December 31, 2007) and \$3,147 million related to the U.S. dollar partnership contribution receivable (\$3,444 million at December 31, 2007). A \$0.01 change in the U.S. to Canadian dollar exchange rate would have resulted in an \$18 million change in foreign exchange (gain) loss at December 31, 2008.

INTEREST RATE RISK

Interest rate risk arises from changes in market interest rates that may affect the fair value or future cash flows from the Company's financial assets or liabilities. The Company partially mitigates its exposure to interest rate changes by maintaining a mix of both fixed and floating rate debt.

At December 31, 2008, the increase or decrease in net earnings for each one percent change in interest rates on floating rate debt amounts to \$12 million (2007 – \$14 million; 2006 – \$11 million).

21. Supplementary Information

A) PER SHARE AMOUNTS

The following table summarizes the Common Shares used in calculating Net Earnings per Common Share:

For the years ended December 31	2008	2007	2006
Weighted Average Common Shares Outstanding – Basic	750.1	756.8	819.9
Effect of Stock Options and Other Dilutive Securities	1.7	7.8	16.6
Weighted Average Common Shares Outstanding – Diluted	751.8	764.6	836.5

B) NET CHANGE IN NON-CASH WORKING CAPITAL FROM CONTINUING OPERATIONS

For the years ended December 31	2008	2007	2006
Operating Activities			
Accounts receivable and accrued revenues	\$ 452	\$ 33	\$ 3,128
Inventories	222	42	(75)
Accounts payable and accrued liabilities	(354)	(78)	(260)
Income tax payable	(589)	(5)	550
	\$ (269)	\$ (8)	\$ 3,343
Investing Activities			
Accounts payable and accrued liabilities	\$ 89	\$ 86	\$ 19

C) SUPPLEMENTARY CASH FLOW INFORMATION – CONTINUING OPERATIONS

For the years ended December 31	2008	2007	2006
Interest Paid	\$ 771	\$ 698	\$ 387
Income Taxes Paid	\$ 1,641	\$ 1,423	\$ 450

22. Commitments and Contingencies

COMMITMENTS

As at December 31, 2008	2009	2010	2011	2012	2013	Thereafter	Total
Pipeline Transportation	\$ 469	\$ 492	\$ 478	\$ 500	\$ 477	\$ 2,533	\$ 4,949
Purchases of Goods and Services	1,061	466	290	227	166	534	2,744
Product Purchases	23	23	20	18	18	43	145
Operating Leases ⁽¹⁾	70	71	120	176	158	2,678	3,273
Capital Commitments	5	2	104	–	–	38	149
Other Long-Term Commitments	15	11	5	1	–	–	32
Total	\$ 1,643	\$ 1,065	\$ 1,017	\$ 922	\$ 819	\$ 5,826	\$ 11,292
Product Sales	\$ 38	\$ 39	\$ 41	\$ 44	\$ 45	\$ 149	\$ 356

(1) Operating leases consist of building leases, including The Bow (See Note 5).

In addition to the above, the Company has made commitments related to its risk management program (See Note 20).

CONTINGENCIES

LEGAL PROCEEDINGS

The Company is involved in various legal claims associated with the normal course of operations. The Company believes it has made adequate provision for such legal claims.

DISCONTINUED MERCHANT ENERGY OPERATIONS

During the period between 2003 and 2005, EnCana and its indirect wholly owned U.S. marketing subsidiary, WD Energy Services Inc. ("WD"), along with other energy companies, were named as defendants in several lawsuits, some of which were class action lawsuits, relating to sales of natural gas from 1999 to 2002. The lawsuits allege that the defendants engaged in a conspiracy with unnamed competitors in the natural gas markets in California in violation of U.S. and California anti-trust and unfair competition laws.

Without admitting any liability in the lawsuits, WD agreed to settle all of the class action lawsuits in both state and federal court for payment of \$20.5 million and \$2.4 million, respectively. Also, as previously disclosed, without admitting any liability whatsoever, WD concluded settlements with the U.S. Commodity Futures Trading Commission ("CFTC") for \$20 million and of a previously disclosed consolidated class action lawsuit in the United States District Court in New York for \$8.2 million. Also, without admitting any liability whatsoever, WD concluded settlements with a group of individual plaintiffs for \$23 million.

The remaining lawsuit was commenced by E. & J. Gallo Winery ("Gallo"). The Gallo lawsuit claims damages in excess of \$30 million. California law allows for the possibility that the amount of damages assessed could be tripled.

The Company and WD intend to vigorously defend against this outstanding claim; however, the Company cannot predict the outcome of these proceedings or any future proceedings against the Company, whether these proceedings would lead to monetary damages which could have a material adverse effect on the Company's financial position, or whether there will be other proceedings arising out of these allegations.

ASSET RETIREMENT

EnCana is responsible for the retirement of long-lived assets related to its oil and gas properties, refining facilities and Midstream facilities at the end of their useful lives. The Company has recognized a liability of \$1,265 million based on current legislation and estimated costs. Actual costs may differ from those estimated due to changes in legislation and changes in costs.

INCOME TAX MATTERS

The operations of the Company are complex, and related tax interpretations, regulations and legislation in the various jurisdictions that EnCana operates in are continually changing. As a result, there are usually some tax matters under review. The Company believes that the provision for taxes is adequate.

23. United States Accounting Principles and Reporting

The Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in Canada ("Canadian GAAP") which, in most respects, conform to accounting principles generally accepted in the United States ("U.S. GAAP"). The significant differences between Canadian GAAP and U.S. GAAP are described in this note.

RECONCILIATION OF NET EARNINGS UNDER CANADIAN GAAP TO U.S. GAAP

For the years ended December 31	Note	2008	2007	2006
Net Earnings – Canadian GAAP		\$ 5,944	\$ 3,959	\$ 5,652
Less:				
Net Earnings From Discontinued Operations – Canadian GAAP		–	75	601
Net Earnings From Continuing Operations – Canadian GAAP		5,944	3,884	5,051
Increase (Decrease) in Net Earnings from Continuing Operations Under U.S. GAAP:				
Revenues, net of royalties	A	–	(15)	179
Operating	A, D ii)	(46)	3	(15)
Depreciation, depletion and amortization	B, D ii)	(1,755)	86	95
Administrative	D ii)	(27)	1	(8)
Interest, net	A	(3)	(2)	(15)
Stock-based compensation – options	C	2	(5)	–
Income tax expense	E	695	(204)	(80)
Net Earnings From Continuing Operations – U.S. GAAP		4,810	3,748	5,207
Net Earnings From Discontinued Operations – U.S. GAAP		–	75	644
Net Earnings Before Change in Accounting Policy – U.S. GAAP		4,810	3,823	5,851
Cumulative Effect of Change in Accounting Policy, net of tax	D ii)	–	–	(15)
Net Earnings – U.S. GAAP		\$ 4,810	\$ 3,823	\$ 5,836
Net Earnings per Common Share Before Change in Accounting Policy – U.S. GAAP				
Basic		\$ 6.41	\$ 5.05	\$ 7.14
Diluted		\$ 6.40	\$ 5.00	\$ 6.99
Net Earnings per Common Share Including Cumulative Effect of Change in Accounting Policy – U.S. GAAP				
Basic		\$ 6.41	\$ 5.05	\$ 7.12
Diluted		\$ 6.40	\$ 5.00	\$ 6.98

CONSOLIDATED STATEMENT OF EARNINGS – U.S. GAAP

For the years ended December 31	Note	2008	2007	2006
Revenues, Net of Royalties	A	\$ 30,064	\$ 21,431	\$ 16,578
Expenses				
Production and mineral taxes		478	291	349
Transportation and selling		1,704	1,010	1,070
Operating	A, D ii)	2,521	2,275	1,670
Purchased product		11,186	8,583	2,862
Depreciation, depletion and amortization	B, D ii)	5,978	3,730	3,017
Administrative	D ii)	500	383	279
Interest, net	A	589	430	411
Accretion of asset retirement obligation		79	64	50
Foreign exchange (gain) loss, net		423	(164)	14
Stock-based compensation – options	C	(2)	5	–
(Gain) loss on divestitures		(140)	(65)	(323)
Net Earnings Before Income Tax		6,748	4,889	7,179
Income tax expense	E	1,938	1,141	1,972
Net Earnings From Continuing Operations – U.S. GAAP		4,810	3,748	5,207
Net Earnings From Discontinued Operations – U.S. GAAP		–	75	644
Net Earnings Before Change in Accounting Policy – U.S. GAAP		4,810	3,823	5,851
Cumulative Effect of Change in Accounting Policy, net of tax	D ii)	–	–	(15)
Net Earnings – U.S. GAAP		\$ 4,810	\$ 3,823	\$ 5,836
Net Earnings From Continuing Operations per Common Share – U.S. GAAP				
Basic		\$ 6.41	\$ 4.95	\$ 6.35
Diluted		\$ 6.40	\$ 4.90	\$ 6.22
Net Earnings From Discontinued Operations per Common Share – U.S. GAAP				
Basic		\$ –	\$ 0.10	\$ 0.79
Diluted		\$ –	\$ 0.10	\$ 0.77
Net Earnings per Common Share Before Change in Accounting Policy – U.S. GAAP				
Basic		\$ 6.41	\$ 5.05	\$ 7.14
Diluted		\$ 6.40	\$ 5.00	\$ 6.99
Net Earnings per Common Share Including Cumulative Effect of Change in Accounting Policy – U.S. GAAP				
Basic		\$ 6.41	\$ 5.05	\$ 7.12
Diluted		\$ 6.40	\$ 5.00	\$ 6.98

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME – U.S. GAAP

For the years ended December 31	Note	2008	2007	2006
Net Earnings – U.S. GAAP		\$ 4,810	\$ 3,823	\$ 5,836
Change in Fair Value of Financial Instruments	A	2	–	4
Foreign Currency Translation Adjustment	B, D ii), F	(2,217)	1,707	(224)
Compensation Plans	F	(12)	1	–
Comprehensive Income		\$ 2,583	\$ 5,531	\$ 5,616

CONSOLIDATED STATEMENT OF ACCUMULATED OTHER COMPREHENSIVE INCOME – U.S. GAAP

For the years ended December 31	Note	2008	2007	2006
Balance, Beginning of Year		\$ 3,038	\$ 1,330	\$ 1,598
Change in Fair Value of Financial Instruments	A	2	–	4
Foreign Currency Translation Adjustment	B, F	(2,217)	1,707	(224)
Compensation Plans	D i), F	(12)	1	(48)
Balance, End of Year		\$ 811	\$ 3,038	\$ 1,330

CONSOLIDATED STATEMENT OF RETAINED EARNINGS – U.S. GAAP

For the years ended December 31		2008	2007	2006
Retained Earnings, Beginning of Year		\$ 12,976	\$ 11,374	\$ 9,327
Net Earnings		4,810	3,823	5,836
Dividends on Common Shares		(1,199)	(603)	(304)
Charges for Normal Course Issuer Bid		(243)	(1,618)	(3,485)
Retained Earnings, End of Year		\$ 16,344	\$ 12,976	\$ 11,374

CONDENSED CONSOLIDATED BALANCE SHEET – U.S. GAAP

As at December 31		2008		2007	
	Note	As Reported	U.S. GAAP	As Reported	U.S. GAAP
Assets					
Current Assets	D i)	\$ 5,602	\$ 5,604	\$ 4,444	\$ 4,446
Property, Plant and Equipment (includes unproved properties and major development projects of \$4,767 and \$3,509 as of December 31, 2008 and 2007, respectively)	B, D ii)	59,354	59,313	59,821	59,729
Accumulated Depreciation, Depletion and Amortization		(23,930)	(25,451)	(23,956)	(23,669)
Property, Plant and Equipment, net (Full Cost Method for Oil and Gas Activities)		35,424	33,862	35,865	36,060
Investments and Other Assets	D i)	727	681	607	557
Partnership Contribution Receivable		2,834	2,834	3,147	3,147
Risk Management		234	234	18	18
Goodwill		2,426	2,426	2,893	2,893
		\$ 47,247	\$ 45,641	\$ 46,974	\$ 47,121
Liabilities and Shareholders' Equity					
Current Liabilities	A, D i), ii)	\$ 3,894	\$ 4,201	\$ 6,330	\$ 6,574
Long-Term Debt		8,755	8,755	8,840	8,840
Other Liabilities	A, D i), ii)	576	613	242	277
Partnership Contribution Payable		2,857	2,857	3,163	3,163
Risk Management		7	7	29	29
Asset Retirement Obligation		1,265	1,265	1,458	1,458
Future Income Taxes	E	6,919	6,198	6,208	6,172
		24,273	23,896	26,270	26,513
Share Capital	C				
Common shares, no par value		4,557	4,590	4,479	4,514
Outstanding: 2008 – 750.4 million shares 2007 – 750.2 million shares					
Paid in Surplus		–	–	80	80
Retained Earnings		17,584	16,344	13,082	12,976
Accumulated Other Comprehensive Income	A, B, D i), F	833	811	3,063	3,038
		22,974	21,745	20,704	20,608
		\$ 47,247	\$ 45,641	\$ 46,974	\$ 47,121

CONDENSED CONSOLIDATED STATEMENT OF CASH FLOWS – U.S. GAAP

For the years ended December 31	2008	2007	2006
Operating Activities			
Net earnings from continuing operations	\$ 4,810	\$ 3,748	\$ 5,207
Depreciation, depletion and amortization	5,978	3,730	3,017
Future income taxes	951	(592)	1,030
Unrealized (gain) loss on risk management	(2,729)	1,251	(2,229)
Unrealized foreign exchange (gain) loss	417	41	–
Accretion of asset retirement obligation	79	64	50
(Gain) loss on divestitures	(140)	(65)	(323)
Other	(8)	97	242
Cash flow from discontinued operations	–	–	118
Net change in other assets and liabilities	(259)	(16)	138
Net change in non-cash working capital from continuing operations	(269)	171	3,343
Net change in non-cash working capital from discontinued operations	–	–	(2,669)
Cash From Operating Activities	\$ 8,830	\$ 8,429	\$ 7,924
Cash (Used in) Investing Activities	\$ (7,528)	\$ (8,175)	\$ (3,333)
Cash (Used in) From Financing Activities	\$ (1,439)	\$ (119)	\$ (4,294)

NOTES:

A) DERIVATIVE INSTRUMENTS AND HEDGING

On January 1, 2004, the Company implemented under Canadian GAAP, EIC 128 "Accounting For Trading, Speculative or Non-Hedging Derivative Financial Instruments" which requires derivatives not designated as hedges to be recorded in the balance sheet as either assets or liabilities at their fair value. Changes in the derivatives' fair value are recognized in current period earnings. Under the transitional rules any gain or loss at the implementation date is deferred and recognized into revenue once realized. Currently, Management has not designated any of the financial instruments as hedges.

The adoption of EIC 128 at January 1, 2004 resulted in the recognition of a \$235 million deferred loss which was recognized into earnings when realized. As at December 31, 2007, under Canadian GAAP, the remaining transition amount had been fully recognized into net earnings.

For U.S. GAAP, the Company adopted Statement of Financial Accounting Standards ("SFAS") 133 effective January 1, 2001. SFAS 133 requires that all derivatives be recorded in the balance sheet as either assets or liabilities at their fair value. Changes in the derivatives' fair value are recognized in current period earnings unless specific hedge accounting criteria are met. Management has currently not designated any of the financial instruments as hedges for U.S. GAAP purposes under SFAS 133. Any gain or loss on implementation of SFAS 133 was recorded in Other Comprehensive Income. These transitional amounts are recognized into net earnings as the positions are realized.

Unrealized gain (loss) on derivatives relate to:

For the years ended December 31	2008	2007	2006
Commodity Prices (Revenues, net of royalties)	\$ 2,729	\$ (1,249)	\$ 2,327
Interest and Currency Swaps (Interest, net)	(3)	(2)	(11)
Total Unrealized Gain (Loss)	\$ 2,726	\$ (1,251)	\$ 2,316
Amounts Allocated to Continuing Operations	\$ 2,726	\$ (1,251)	\$ 2,229
Amounts Allocated to Discontinued Operations	—	—	87
	\$ 2,726	\$ (1,251)	\$ 2,316

In 2008, the remaining balance related to the transitional amounts in Accumulated Other Comprehensive Income was recognized in net earnings for U.S. GAAP.

B) FULL COST ACCOUNTING

Under U.S. GAAP, a ceiling test is applied to ensure the unamortized capitalized costs in each cost centre do not exceed the sum, net of applicable income taxes, of the present value, discounted at 10 percent, of the estimated future net revenues calculated on the basis of estimated value of future production from proved reserves using oil and gas prices at the balance sheet date, less related unescalated estimated future development and production costs, plus unimpaired unproved property costs. Depletion charges under U.S. GAAP are also calculated by reference to proved reserves estimated using oil and gas prices at the balance sheet date.

Under Canadian GAAP, a similar ceiling test calculation is performed with the exception that cash flows from proved reserves are undiscounted and utilize forecast pricing and future development and production costs to determine whether impairment exists. The impairment amount is measured using the fair value of proved and probable reserves. Depletion charges under Canadian GAAP are also calculated by reference to proved reserves estimated using estimated future prices and costs.

At December 31, 2008, the Company's capitalized costs of oil and gas properties in the United States exceeded the full cost ceiling resulting in a non-cash U.S. GAAP write-down of \$1.8 billion charged to depreciation, depletion and amortization (\$1.1 billion after-tax). Additional depletion was also recorded in 2001, and certain prior years, as a result of the ceiling test difference between Canadian GAAP and U.S. GAAP. As a result, the depletion base of unamortized capitalized costs is less for U.S. GAAP purposes.

The U.S. GAAP adjustment for the difference in depletion calculations results in an impact to DD&A charges and foreign currency translation adjustment of \$13.3 million decrease and \$0.8 million increase respectively (2007 – \$85.4 million decrease and \$2.9 million increase; 2006 – \$97 million decrease and \$1.2 million decrease).

C) STOCK-BASED COMPENSATION – CPL REORGANIZATION

Under Financial Accounting Standards Board ("FASB") Interpretation No. 44, "Accounting for Certain Transactions Involving Stock Compensation", compensation expense must be recorded if the intrinsic value of the stock options is not exactly the same immediately before and after an equity restructuring. As part of the corporate reorganization of CPL, an equity restructuring occurred which resulted in CPL stock options being replaced with stock options granted by EnCana, as described in Note 17. This resulted in the replacement options having a different intrinsic value after the restructuring than prior to the restructuring. Canadian GAAP does not require revaluation of these options.

D) COMPENSATION PLANS

i) Pensions and Other Post-Employment Benefits

For the year ended December 31, 2006, the Company adopted, for U.S. GAAP purposes, SFAS 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)". SFAS 158 requires EnCana to recognize the over-funded or under-funded status of defined benefit and post-employment plans on the balance sheet as an asset or liability and to recognize changes in the funded status through Other Comprehensive Income. Canadian GAAP does not require the Company to recognize the funded status of these plans on its balance sheet.

ii) Liability-Based Stock Compensation Plans

Under Canadian GAAP, obligations for liability-based stock compensation plans are recorded using the intrinsic-value method of accounting. For U.S. GAAP purposes, the Company adopted SFAS 123(R), "Share-Based Payment" for the year ended December 31, 2006 using the modified-prospective approach. Under SFAS 123(R), the intrinsic-value method of accounting for liability-based stock compensation plans is no longer an alternative. Liability-based stock compensation plans, including tandem share appreciation rights, performance tandem share appreciation rights, share appreciation rights, performance share appreciation rights and deferred share units, are required to be re-measured at fair value at each reporting period up until the settlement date.

To the extent compensation cost relates to employees directly involved in natural gas and crude oil exploration and development activities, such amounts are capitalized to property, plant and equipment. Amounts not capitalized are recognized as administrative expenses or operating expenses. The current period adjustments have the following impact:

- Net capital assets increased by \$37.7 million (2007 – \$8.4 million decrease)
- Current liabilities increased by \$111.4 million (2007 – \$10.8 million decrease)
- Other liabilities decreased by \$0.5 million (2007 – \$2.8 million decrease)
- Other comprehensive income increased by \$5.9 million (2007 – \$0.5 million increase)
- Operating expenses increased by \$46.1 million (2007 – \$3.3 million decrease)
- Administrative expenses increased by \$26.7 million (2007 – \$0.5 million decrease)
- Depreciation, depletion and amortization expenses increased by \$9.9 million (2007 – \$0.9 million decrease)

As the Company adopted SFAS 123(R) using the modified prospective approach, prior periods have not been restated.

SFAS 123(R), under the modified prospective approach, requires the cumulative impact of a change in an accounting policy to be presented in the current year Consolidated Statement of Earnings. The cumulative effect, net of tax, of initially adopting SFAS 123(R) January 1, 2006 was a loss of \$15 million.

E) INCOME TAXES

Under U.S. GAAP, enacted tax rates and legislative changes are used to calculate current and future income taxes; whereas Canadian GAAP uses substantively enacted tax rates and legislative changes. In 2007, a Canadian tax legislative change was substantively enacted for Canadian GAAP; however, this tax legislative change was not considered enacted for U.S. GAAP by December 31, 2007. This tax legislative change was still not considered enacted for U.S. GAAP by December 31, 2008. Accordingly, there was no difference in 2008 (2007 – increase to income tax expense of \$179 million; 2006 – nil) for U.S. GAAP.

The remaining differences resulted from the future income tax adjustments included in the Reconciliation of Net Earnings under Canadian GAAP to U.S. GAAP and the Condensed Consolidated Balance Sheet include the effect of such rate differences, if any, as well as the tax effect of the other reconciling items noted.

The following table provides a reconciliation of the statutory rate to the actual tax rate:

For the years ended December 31	2008	2007	2006
Net Earnings Before Income Tax – U.S. GAAP	\$ 6,748	\$ 4,889	\$ 7,179
Canadian Statutory Rate	29.7%	32.3%	34.7%
Expected Income Tax	2,001	1,579	2,491
Effect on Taxes Resulting from:			
Non-deductible Canadian Crown payments	–	–	97
Canadian resource allowance	–	–	(16)
Statutory and other rate differences	12	76	(98)
Effect of tax rate changes	–	(301)	(457)
Non-taxable downstream partnership income	6	(70)	–
International financing	(309)	(62)	–
Foreign exchange (gains) losses not included in net earnings	49	–	–
Non-taxable capital (gains) losses	84	(124)	(1)
Other	95	43	(44)
Income Tax – U.S. GAAP	\$ 1,938	\$ 1,141	\$ 1,972
Effective Tax Rate	28.7%	23.3%	27.5%

The net future income tax liability is comprised of:

As at December 31	2008	2007
Future Tax Liabilities		
Property, plant and equipment in excess of tax values	\$ 4,641	\$ 5,340
Timing of partnership items	924	961
Risk management	958	89
Future Tax Assets		
Non-capital and net operating losses carried forward	(66)	(44)
Other	(259)	(174)
Net Future Income Tax Liability	\$ 6,198	\$ 6,172

F) OTHER COMPREHENSIVE INCOME

SFAS 158 requires the change in the funded status of defined benefit and post-employment plans on the balance sheet and changes in the funded status through comprehensive income. In 2008, a loss of \$12.0 million, net of tax was recognized in other comprehensive income (2007 – \$1.2 million gain net of tax) as noted in D i). On adoption of SFAS 158, as required, the transitional amount of \$48 million, net of tax was booked directly to Accumulated Other Comprehensive Income.

The foreign currency translation adjustment includes the effect of the accumulated U.S. GAAP differences.

G) JOINT VENTURE WITH CONOCOPHILLIPS

Under Canadian GAAP, the Integrated Oil operations that are jointly controlled are proportionately consolidated. U.S. GAAP requires the Downstream Refining operations included in the Integrated Oil Division be accounted for using the equity method. However, under an accommodation of the U.S. Securities and Exchange Commission ("SEC"), accounting for jointly controlled investments does not require reconciliation from Canadian to U.S. GAAP if the joint venture is jointly controlled by all parties having an equity interest in the entity. This is the case for the Downstream Refining operations. Equity accounting for the Downstream Refining operations would have no impact on EnCana's net earnings or retained earnings. As required, the following disclosures are provided for the Downstream Refining operations of the joint venture.

Income Statement

For the year ended December 31	2008	2007
Operating Cash Flow (See Note 5)	\$ (241)	\$ 1,074
Depreciation, depletion and amortization	(188)	(159)
Other	19	(5)
Net Income	\$ (410)	\$ 910

Balance Sheet

As at December 31	2008	2007
Current Assets	\$ 321	\$ 1,172
Long-term Assets	4,157	3,851
Current Liabilities	422	644
Long-term Liabilities	35	21

Statement of Cash Flows

For the year ended December 31	2008	2007
Cash From Operating Activities	\$ 118	\$ 885
Cash (Used in) Investing Activities	(519)	(322)
Cash (Used in) From Financing Activities	—	—

H) CONSOLIDATED STATEMENT OF CASH FLOWS

Certain items presented as investing or financing activities under Canadian GAAP are required to be presented as operating activities under U.S. GAAP. Cash tax on sale of assets presented as investing activities under Canadian GAAP is presented as operating activities under U.S. GAAP.

I) DIVIDENDS DECLARED ON COMMON STOCK

For the years ended December 31	2008	2007	2006
Dividends per share	\$ 1.60	\$ 0.80	\$ 0.375

J) RECENT ACCOUNTING PRONOUNCEMENTS

As of January 1, 2008, EnCana adopted, for U.S. GAAP purposes, SFAS 157, "Fair Value Measurements". SFAS 157 provides a common definition of fair value, establishes a framework for measuring fair value under U.S. GAAP and expands disclosures about fair value measurements. This standard applies when other accounting pronouncements require fair value measurements and does not require new fair value measurements. The adoption of this standard did not have a material impact on EnCana's Consolidated Financial Statements.

As of January 1, 2008, EnCana adopted, for U.S. GAAP purposes, measurement requirements under SFAS 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)". This standard also requires EnCana to measure the funded status of a plan as of the balance sheet date. The adoption of the change in measurement date did not have a material impact on EnCana's Consolidated Financial Statements.

In May 2008, the FASB issued Statement of Financial Accounting Standards No. 162, "*The Hierarchy of Generally Accepted Accounting Principles*". This standard became effective November 15, 2008 following the SEC's approval of the Public Company Accounting Oversight Board Auditing amendments to AU Section, 411 "*The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles*". The statement is intended to improve financial reporting by identifying a consistent hierarchy for selecting accounting principles to be used in preparing financial statements that are presented in conformity with U.S. GAAP. The adoption of this standard did not have a material impact on EnCana's Consolidated Financial Statements.

The Company has assessed new and revised accounting pronouncements that have been issued that are not yet effective and determined that the following may have a significant impact on the Company:

- As of January 1, 2009, EnCana will be required to adopt, for U.S. GAAP purposes, SFAS 141(R), "Business Combinations", which replaces SFAS 141. This revised standard requires assets and liabilities acquired in a business combination, contingent consideration, and certain acquired contingencies to be measured at their fair values as of the date of acquisition. In addition, acquisition-related and restructuring costs are to be recognized separately from the business combination. The adoption of this standard will impact EnCana's U.S. GAAP accounting treatment of business combinations entered into after January 1, 2009.
- As of January 1, 2009, EnCana will be required to adopt, for U.S. GAAP purposes, SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements, an Amendment of ARB No. 51". This standard requires a noncontrolling interest in a subsidiary to be classified as a separate component of equity. The standard also changes the way the U.S. GAAP Consolidated Statement of Earnings is presented by requiring net earnings to include the amounts attributable to both the parent and the noncontrolling interest and to disclose these respective amounts. The adoption of this standard should not have a material impact on EnCana's Consolidated Financial Statements.
- As of December 31, 2009, EnCana will be required to prospectively adopt the new reserves requirements that arise from the completion of the SEC's project, *Modernization of Oil and Gas Reporting*. The new rules include provisions that permit the use of new technologies to establish proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes. Additionally, oil and gas reserves will be reported using an average price based upon the prior 12-month period rather than year-end prices. The new rules will affect the reserve estimate used in the calculation of DD&A and the ceiling test for U.S. GAAP purposes. The Company is assessing the impact these new rules will have on its Consolidated Financial Statements.

Supplementary Oil and Gas Information – SFAS 69 (unaudited)

For the year ended December 31, 2008 (prepared in US\$)

OTHER DISCLOSURES ABOUT OIL AND GAS ACTIVITIES

The tables in this section set forth oil and gas information prepared by EnCana in accordance with U.S. disclosure standards, including Statement of Financial Accounting Standard Number 69 ("SFAS 69").

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS AND CHANGES THEREIN

In calculating the standardized measure of discounted future net cash flows, year-end constant prices and cost assumptions were applied to EnCana's annual future production from proved reserves to determine cash inflows. Future production and development costs are based on constant price assumptions and assume the continuation of existing economic, operating and regulatory conditions. Future income taxes are calculated by applying statutory income tax rates to future pre-tax cash flows after provision for the tax cost of the oil and natural gas properties based upon existing laws and regulations. The discount was computed by application of a 10 percent discount factor to the future net cash flows. The calculation of the standardized measure of discounted future net cash flows is based upon the discounted future net cash flows prepared by EnCana's independent qualified reserves evaluators in relation to the reserves they respectively evaluated, and adjusted to the extent provided by contractual arrangements such as price risk management activities, in existence at year end and to account for asset retirement obligations and future income taxes.

EnCana cautions that the discounted future net cash flows relating to proved oil and gas reserves are an indication of neither the fair market value of EnCana's oil and gas properties, nor the future net cash flows expected to be generated from such properties. The discounted future net cash flows do not include the fair market value of exploratory properties and probable or possible oil and gas reserves, nor is consideration given to the effect of anticipated future changes in crude oil and natural gas prices, development, asset retirement and production costs and possible changes to tax and royalty regulations. The prescribed discount rate of 10 percent may not appropriately reflect future interest rates. The computation also excludes values attributable to EnCana's Market Optimization interests.

Net Proved Reserves (unaudited)

Net Proved Reserves

(EnCana Share After Royalties) ^(1,2)

Constant Pricing

	Natural Gas (billions of cubic feet)			Crude Oil and Natural Gas Liquids (millions of barrels)			
	Canada	United States	Total	Canada	United States	Ecuador ⁽³⁾	Total
2006							
Beginning of year	6,517	5,267	11,784	932.5	53.1	135.0	1,120.6
Revisions and improved recovery	301	(88)	213	(39.0)	(1.1)	—	(40.1)
Extensions and discoveries	1,014	606	1,620	238.7	6.4	—	245.1
Purchase of reserves in place	—	68	68	—	0.3	—	0.3
Sale of reserves in place	(6)	(32)	(38)	(0.1)	—	(130.6)	(130.7)
Production	(798)	(431)	(1,229)	(52.7)	(4.7)	(4.4)	(61.8)
End of year	7,028	5,390	12,418	1,079.4 ⁽⁴⁾	54.0	—	1,133.4
Developed	4,718	2,964	7,682	316.9	33.5	—	350.4
Undeveloped	2,310	2,426	4,736	762.5	20.5	—	783.0
Total	7,028	5,390	12,418	1,079.4 ⁽⁴⁾	54.0	—	1,133.4
2007							
Beginning of year	7,028	5,390	12,418	1,079.4	54.0	—	1,133.4
Revisions and improved recovery	87	78	165	75.5	3.6	—	79.1
Extensions and discoveries	949	827	1,776	155.8	5.9	—	161.7
Purchase of reserves in place	63	211	274	0.2	—	—	0.2
Sale of reserves in place	(24)	(7)	(31)	(398.2) ⁽⁵⁾	—	—	(398.2)
Production	(811)	(491)	(1,302)	(43.8)	(5.2)	—	(49.0)
End of year	7,292	6,008	13,300	868.9	58.3	—	927.2
Developed	4,868	3,368	8,236	289.5	37.0	—	326.5
Undeveloped	2,424	2,640	5,064	579.4	21.3	—	600.7
Total	7,292	6,008	13,300	868.9	58.3	—	927.2
2008							
Beginning of year	7,292	6,008	13,300	868.9	58.3	—	927.2
Revisions and improved recovery	148	(166)	(18)	112.8	(3.6)	—	109.2
Extensions and discoveries	1,311	655	1,966	17.0	3.8	—	20.8
Purchase of reserves in place	32	7	39	0.2	—	—	0.2
Sale of reserves in place	(129)	(75)	(204)	(0.9)	(2.0)	—	(2.9)
Production	(807)	(598)	(1,405)	(44.0)	(4.9)	—	(48.9)
End of year	7,847	5,831	13,678	954.0	51.6	—	1,005.6
Developed	4,945	3,720	8,665	334.4	33.9	—	368.3
Undeveloped	2,902	2,111	5,013	619.6	17.7	—	637.3
Total	7,847	5,831	13,678	954.0	51.6	—	1,005.6

(1) Definitions:

- a. "Net" reserves are the remaining reserves of EnCana, after deduction of estimated royalties and including royalty interests.
- b. "Proved" reserves are the estimated quantities of crude oil, natural gas and NGLs which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made.
- c. "Proved Developed" reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
- d. "Proved Undeveloped" reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(2) EnCana does not file any estimates of total net proved crude oil or natural gas reserves with any U.S. federal authority or agency other than the SEC.

(3) The Corporation divested its Ecuadorian operations in 2006.

(4) Proved crude oil and NGLs reserves at December 31, 2006 include approximately 800 million barrels of bitumen, of which 796 million barrels was attributable to the Corporation's interests in Foster Creek and Christina Lake on that date. Effective January 2, 2007, these interests were contributed to FCCL in which the Corporation has a 50 percent interest. Accordingly, effective as at that date, the Corporation's reserves associated with those properties were reduced by 398 million barrels.

(5) Includes approximately 398 million barrels attributable to the contribution of interests to FCCL.

(6) Reserves estimates at December 31, 2008 for properties located in Alberta have been prepared using the Alberta royalty framework which came into effect on January 1, 2009.

Standardized Measure of Discounted Future Net Cash Flows (unaudited)

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

(\$ millions)	Canada			United States		
	2008	2007	2006	2008	2007	2006
Future cash inflows	64,308	95,778	72,262	26,620	38,398	27,165
Less future:						
Production costs	23,017	25,089	20,471	6,079	5,869	4,123
Development costs	9,800	10,171	9,355	5,227	6,943	4,715
Asset retirement obligation payments	2,995	3,320	2,397	488	532	396
Income taxes	5,746	12,871	8,816	2,961	7,375	5,349
Future net cash flows	22,750	44,327	31,223	11,865	17,679	12,582
Less 10% annual discount for estimated timing of cash flows	10,036	21,663	14,627	5,218	8,196	6,128
Discounted future net cash flows	12,714	22,664	16,596	6,647	9,483	6,454

(\$ millions)	Total		
	2008	2007	2006
Future cash inflows	90,928	134,176	99,427
Less future:			
Production costs	29,096	30,958	24,594
Development costs	15,027	17,114	14,070
Asset retirement obligation payments	3,483	3,852	2,793
Income taxes	8,707	20,246	14,165
Future net cash flows	34,615	62,006	43,805
Less 10% annual discount for estimated timing of cash flows	15,254	29,859	20,755
Discounted future net cash flows	19,361	32,147	23,050

Changes in Standardized Measure of Discounted Future Net Cash Flows (unaudited)

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

(\$ millions)	Canada			United States			Ecuador		
	2008	2007	2006	2008	2007	2006	2008	2007	2006
Balance, beginning of year	22,664	16,596	20,137	9,483	6,454	11,472	—	—	1,568
Changes resulting from:									
Sales of oil and gas produced during the period	(7,346)	(6,055)	(5,970)	(4,125)	(3,281)	(2,373)	—	—	(142)
Discoveries and extensions, net of related costs	2,031	3,632	2,429	904	1,591	877	—	—	—
Purchases of proved reserves in place	58	120	—	14	372	69	—	—	—
Sales of proved reserves in place	(321)	(1,283)	(19)	(197)	(15)	(85)	—	—	(1,359)
Net change in prices and production costs	(14,632)	9,671	(6,260)	(4,204)	4,818	(7,636)	—	—	—
Revisions to quantity estimates	1,736	603	1,486	667	830	265	—	—	—
Accretion of discount	2,905	2,087	2,809	1,346	924	1,714	—	—	—
Previously estimated development costs incurred net of change in future development costs	1,923	(259)	(910)	315	(907)	(350)	—	—	(46)
Other	321	(341)	(782)	88	(113)	(381)	—	—	—
Net change in income taxes	3,375	(2,107)	3,676	2,356	(1,190)	2,882	—	—	(21)
Balance, end of year	12,714	22,664	16,596	6,647	9,483	6,454	—	—	—

(\$ millions)	Total								
	2008	2007	2006						
Balance, beginning of year	32,147	23,050	33,177						
Changes resulting from:									
Sales of oil and gas produced during the period	(11,471)	(9,336)	(8,485)						
Discoveries and extensions, net of related costs	2,935	5,223	3,306						
Purchases of proved reserves in place	72	492	69						
Sales of proved reserves in place	(518)	(1,298)	(1,463)						
Net change in prices and production costs	(18,836)	14,489	(13,896)						
Revisions to quantity estimates	2,403	1,433	1,751						
Accretion of discount	4,251	3,011	4,523						
Previously estimated development costs incurred net of change in future development costs	2,238	(1,166)	(1,306)						
Other	409	(454)	(1,163)						
Net change in income taxes	5,731	(3,297)	6,537						
Balance, end of year	19,361	32,147	23,050						

Results of Operations (unaudited)

Results of Operations (\$ millions)	Canada			United States			Ecuador ⁽¹⁾		
	2008	2007	2006	2008	2007	2006	2008	2007	2006
Oil and gas revenues, net of royalties, transportation and selling costs	8,848	7,361	7,190	5,127	4,065	3,096	—	—	190
Less:									
Operating costs, production and mineral taxes, and accretion of asset retirement obligations	1,502	1,306	1,220	1,002	784	723	—	—	48
Depreciation, depletion and amortization	2,198	2,298	2,146	1,691	1,181	869	—	—	84
Operating income (loss)	5,148	3,757	3,824	2,434	2,100	1,504	—	—	58
Income taxes	1,502	1,114	1,235	937	809	556	—	—	21
Results of operations	3,646	2,643	2,589	1,497	1,291	948	—	—	37

(\$ millions)	Other			Total		
	2008	2007	2006	2008	2007	2006
Oil and gas revenues, net of royalties, transportation and selling costs	2	—	2	13,977	11,426	10,478
Less:						
Operating costs, production and mineral taxes, and accretion of asset retirement obligations	(2)	19	11	2,502	2,109	2,002
Depreciation, depletion and amortization	39	69	10	3,928	3,548	3,109
Operating income (loss)	(35)	(88)	(19)	7,547	5,769	5,367
Income taxes	—	—	—	2,439	1,923	1,812
Results of operations	(35)	(88)	(19)	5,108	3,846	3,555

(1) The sale of EnCana's Ecuador operations was completed in February 2006, and a loss on sale of \$279 million, including indemnities, was recorded. Depreciation, depletion and amortization in 2006 and 2005 represents provisions which have been recorded against the net book value to recognize management's best estimate of the difference between the selling price and the underlying accounting value of the related investments at February 28, 2006.

Capitalized Costs (unaudited)

Capitalized Costs	Canada			United States			Other		
(\$ millions)	2008	2007	2006	2008	2007	2006	2008	2007	2006
Proved oil and gas properties	33,159	36,780	31,546	15,653	13,738	9,796	—	—	—
Unproved oil and gas properties	870	1,380	1,700	3,399	1,852	1,221	122	297	361
Total capital cost	34,029	38,160	33,246	19,052	15,590	11,017	122	297	361
Accumulated DD&A	17,434	19,286	14,261	5,511	3,783	2,595	112	160	98
Net capitalized costs	16,595	18,874	18,985	13,541	11,807	8,422	10	137	263
Total									
(\$ millions)							2008	2007	2006
Proved oil and gas properties							48,812	50,518	41,342
Unproved oil and gas properties							4,391	3,529	3,282
Total capital cost							53,203	54,047	44,624
Accumulated DD&A							23,057	23,229	16,954
Net capitalized costs							30,146	30,818	27,670

Costs Incurred (unaudited)

Costs Incurred	Canada			United States			Ecuador		
(\$ millions)	2008	2007	2006	2008	2007	2006	2008	2007	2006
Acquisitions									
Unproved	32	28	—	1,006	1,048	278	—	—	—
Proved	119	61	47	17	1,565	6	—	—	—
Total acquisitions	151	89	47	1,023	2,613	284	—	—	—
Exploration costs	474	427	403	197	48	236	—	—	1
Development costs	3,328	3,309	3,611	2,418	1,871	1,826	—	—	46
Total costs incurred	3,953	3,825	4,061	3,638	4,532	2,346	—	—	47

	Other			Total		
(\$ millions)	2008	2007	2006	2008	2007	2006
Acquisitions						
Unproved	—	—	—	1,038	1,076	278
Proved	—	—	—	136	1,626	53
Total acquisitions	—	—	—	1,174	2,702	331
Exploration costs	17	60	75	688	535	715
Development costs	—	—	—	5,746	5,180	5,483
Total costs incurred	17	60	75	7,608	8,417	6,529

Supplemental Financial Information – Financial Statistics (unaudited)

Financial Statistics (\$ millions, except per share amounts)	2008					2007				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Total Consolidated										
Cash Flow ⁽¹⁾	9,386	1,299	2,809	2,889	2,389	8,453	1,934	2,218	2,549	1,752
Per share – Basic	12.51	1.73	3.74	3.85	3.19	11.17	2.58	2.96	3.36	2.28
– Diluted	12.48	1.73	3.74	3.85	3.17	11.06	2.56	2.93	3.33	2.25
Net Earnings	5,944	1,077	3,553	1,221	93	3,959	1,082	934	1,446	497
Per share – Basic	7.92	1.44	4.74	1.63	0.12	5.23	1.44	1.24	1.91	0.65
– Diluted	7.91	1.43	4.73	1.63	0.12	5.18	1.43	1.24	1.89	0.64
Operating Earnings ⁽²⁾	4,405	449	1,442	1,469	1,045	4,100	849	1,032	1,369	850
Per share – Diluted	5.86	0.60	1.92	1.96	1.39	5.36	1.12	1.37	1.79	1.09
Continuing Operations										
Cash Flow from Continuing Operations ⁽³⁾	9,386	1,299	2,809	2,889	2,389	8,453	1,934	2,218	2,549	1,752
Net Earnings from Continuing Operations	5,944	1,077	3,553	1,221	93	3,884	1,007	934	1,446	497
Per share – Basic	7.92	1.44	4.74	1.63	0.12	5.13	1.34	1.24	1.91	0.65
– Diluted	7.91	1.43	4.73	1.63	0.12	5.08	1.33	1.24	1.89	0.64
Operating Earnings – Continuing Operations ⁽⁴⁾	4,405	449	1,442	1,469	1,045	4,100	849	1,032	1,369	850
Effective Tax Rates using										
Net Earnings	30.7%									
Operating Earnings, excluding divestitures	28.0%									
Canadian Statutory Rate	29.7%									
Foreign Exchange Rates (US\$ per C\$1)										
Average	0.938	0.825	0.961	0.990	0.996	0.930	1.019	0.957	0.911	0.854
Period end	0.817	0.817	0.944	0.982	0.973	1.012	1.012	1.004	0.940	0.867
Cash Flow Information										
Cash from Operating Activities	8,855	2,043	3,058	1,996	1,758	8,429	2,193	2,180	2,148	1,908
Deduct (Add back):										
Net change in other assets and liabilities	(262)	21	(19)	(171)	(93)	(16)	(21)	1	(16)	20
Net change in non-cash working capital	(269)	723	268	(722)	(538)	(8)	280	(39)	(385)	136
Cash Flow ⁽¹⁾	9,386	1,299	2,809	2,889	2,389	8,453	1,934	2,218	2,549	1,752

- (1) Cash Flow is a non-GAAP measure defined as Cash from Operating Activities excluding net change in other assets and liabilities and net change in non-cash working capital, both of which are defined on the Consolidated Statement of Cash Flows.
- (2) Operating Earnings is a non-GAAP measure defined as Net Earnings excluding the after-tax gain/loss on discontinuance, after-tax effect of unrealized mark-to-market accounting gains/losses on derivative instruments, after-tax gains/losses on translation of U.S. dollar denominated Notes issued from Canada, after-tax foreign exchange gains/losses on settlement of intercompany transactions, future income tax on foreign exchange related to U.S. dollar intercompany debt recognized for tax purposes only and the effect of changes in statutory income tax rates.
- (3) Cash Flow from Continuing Operations is a non-GAAP measure defined as Cash from Operating Activities excluding net change in other assets and liabilities, net change in non-cash working capital from continuing operations, net change in non-cash working capital from discontinued operations and cash flow from discontinued operations.
- (4) Operating Earnings – Continuing Operations is a non-GAAP measure defined as Net Earnings from Continuing Operations excluding the after-tax gain/loss on discontinuance, the after-tax effect of unrealized mark-to-market accounting gains/losses on derivative instruments, after-tax gains/losses on translation of U.S. dollar denominated Notes issued from Canada, after-tax foreign exchange gains/losses on settlement of intercompany transactions, future income tax on foreign exchange related to U.S. dollar intercompany debt recognized for tax purposes only and the effect of changes in statutory income tax rates.

Supplemental Financial Information – Financial Statistics (unaudited)

Financial Statistics (continued)

Common Share Information (\$ millions, except per share amounts)	2008					2007				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Common Shares Outstanding (millions)										
Period end	750.4	750.4	750.3	750.2	750.0	750.2	750.2	749.5	752.8	761.3
Average – Basic	750.1	750.3	750.3	750.2	749.5	756.8	749.8	750.4	758.5	768.4
Average – Diluted	751.8	751.3	751.3	751.3	753.0	764.6	755.1	755.9	765.2	779.6
Price Range (\$ per share)										
TSX – C\$										
High	97.81	68.04	95.91	97.81	79.26	71.21	69.59	67.99	71.21	59.65
Low	41.36	41.36	63.84	76.41	59.95	51.55	60.89	59.33	57.61	51.55
Close	56.96	56.96	67.96	93.36	78.20	67.50	67.50	61.50	65.52	58.40
NYSE – US\$										
High	99.36	64.19	94.41	99.36	79.75	75.85	75.85	65.18	66.87	51.49
Low	34.00	34.00	61.13	74.16	58.13	42.38	60.86	55.13	50.58	42.38
Close	46.48	46.48	65.73	90.93	75.75	67.96	67.96	61.85	61.45	50.63
Dividends Paid (\$ per share)										
Share Volume Traded (millions)	1,893.7	614.9	547.7	376.4	354.7	1,250.9	290.8	301.4	327.4	331.3
Share Value Traded (US\$ millions weekly average)	2,348.6	2,114.5	2,912.5	2,486.0	1,900.5	1,390.9	1,489.3	1,414.4	1,479.5	1,209.5

Financial Metrics	2008					2007				
Debt to Capitalization ⁽¹⁾	28%					32%				
Debt to Adjusted EBITDA ^(1,2)	0.7x					1.1x				
Return on Capital Employed ⁽¹⁾	20%					16%				
Return on Common Equity	27%					21%				

(1) Calculated using Debt defined as the current and long-term portions of Long-Term Debt. Previously calculated using Net Debt defined as Long-Term Debt, plus Current Liabilities less Current Assets.

(2) Calculated on a trailing twelve-month basis.

Net Capital Investment (unaudited)

Financial Statistics (continued)

Net Capital Investment

(\$ millions)	2008	2007
Capital Investment		
Canada		
Canadian Plains	\$ 847	\$ 846
Canadian Foothills	2,299	2,439
Integrated Oil – Canada	656	451
USA	2,615	1,919
Downstream Refining	478	220
Market Optimization	17	6
Corporate & Other	168	154
Capital Investment	7,080	6,035
Acquisitions		
Property		
Canada		
Canadian Foothills	151	75
Integrated Oil – Canada	–	14
USA ⁽¹⁾	1,023	2,613
Divestitures		
Property		
Canada		
Canadian Plains	(39)	–
Canadian Foothills ⁽²⁾	(400)	(213)
Integrated Oil – Canada	(8)	–
USA	(251)	(10)
Corporate & Other ⁽³⁾	(41)	(47)
Corporate		
Corporate & Other ⁽⁴⁾	(165)	(211)
Net Acquisition and Divestiture Activity	270	2,221
Net Capital Investment	\$ 7,350	\$ 8,256

(1) In 2008, mainly includes Haynesville properties; In 2007, mainly includes the Deep Bossier natural gas and land interests of the privately-owned Leor Energy group in East Texas acquired November 20, 2007.

(2) In 2007, consists primarily of the sale of Mackenzie Delta assets which was completed on May 30, 2007.

(3) In 2007, consists primarily of the sale of EnCana's office building project assets, The Bow, which was completed on February 9, 2007 and the sale of Australia assets which was completed on August 15, 2007.

(4) In 2008, mainly includes the sale of interests in Brazil which was completed on September 18, 2008; In 2007, sale of interests in Chad was completed on January 12, 2007 and sale of interests in Oman was completed on November 28, 2007.

Operating Statistics – Volumes (unaudited)

Operating Statistics – After Royalties

Production Volumes by Geographic Region

	Year	2008					2007				
		Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1	
Produced Gas (MMcf/d)											
Canada	2,205	2,181	2,243	2,212	2,181	2,221	2,258	2,243	2,203	2,178	
USA	1,633	1,677	1,674	1,629	1,552	1,345	1,464	1,387	1,303	1,222	
	3,838	3,858	3,917	3,841	3,733	3,566	3,722	3,630	3,506	3,400	
Oil and Natural Gas Liquids⁽¹⁾ (bbls/d)											
Canada	120,230	123,019	119,703	114,121	124,056	119,974	121,346	120,805	119,607	118,087	
USA	13,350	12,831	13,853	13,482	13,232	14,180	14,791	15,578	13,809	12,503	
	133,580	135,850	133,556	127,603	137,288	134,154	136,137	136,383	133,416	130,590	
Total (MMcfe/d)											
Canada	2,926	2,919	2,961	2,897	2,926	2,941	2,986	2,968	2,920	2,887	
USA	1,713	1,754	1,757	1,710	1,631	1,430	1,553	1,480	1,386	1,297	
	4,639	4,673	4,718	4,607	4,557	4,371	4,539	4,448	4,306	4,184	

(1) Natural gas liquids include condensate volumes.

Operating Statistics – Volumes (unaudited)

Operating Statistics – After Royalties

	2008					2007				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Produced Gas (MMcf/d)										
Canadian Plains	842	820	831	856	860	875	876	858	874	891
Canadian Foothills	1,300	1,302	1,351	1,289	1,256	1,255	1,313	1,280	1,231	1,196
USA	1,633	1,677	1,674	1,629	1,552	1,345	1,464	1,387	1,303	1,222
Integrated Oil – Other	63	59	61	67	65	91	69	105	98	91
Total Produced Gas	3,838	3,858	3,917	3,841	3,733	3,566	3,722	3,630	3,506	3,400
Oil and Natural Gas Liquids (bbls/d)										
Light and Medium Oil										
Canadian Plains	31,128	32,147	30,134	30,479	31,752	32,156	31,706	32,064	31,740	33,129
Canadian Foothills	8,473	8,437	8,217	8,376	8,867	8,216	8,441	7,978	7,959	8,489
Heavy Oil										
Canadian Plains	35,029	32,843	34,655	34,618	38,029	38,784	38,581	38,647	38,408	39,510
Integrated Oil – Foster Creek/ Christina Lake	30,183	35,068	31,547	24,671	29,376	26,814	27,190	28,740	27,994	23,269
Integrated Oil – Other	2,729	2,133	2,273	3,009	3,514	2,688	3,040	2,235	2,489	2,990
Natural Gas Liquids ⁽¹⁾										
Canadian Plains	1,181	1,126	1,147	1,189	1,262	1,260	1,422	1,209	1,206	1,203
Canadian Foothills	11,507	11,265	11,730	11,779	11,256	10,056	10,966	9,932	9,811	9,497
USA	13,350	12,831	13,853	13,482	13,232	14,180	14,791	15,578	13,809	12,503
Total Oil and Natural Gas Liquids	133,580	135,850	133,556	127,603	137,288	134,154	136,137	136,383	133,416	130,590
Total (MMcfe/d)	4,639	4,673	4,718	4,607	4,557	4,371	4,539	4,448	4,306	4,184

(1) Natural gas liquids include condensate volumes.

	2008					2007				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Refinery Operations⁽²⁾										
Crude oil capacity (Mbbls/d)	452	452	452	452	452	452	452	452	452	452
Crude oil runs (Mbbls/d)	423	434	412	437	408	432	439	460	396	433
Crude utilization (%)	93%	96%	91%	97%	90%	96%	97%	102%	88%	96%
Refined products (Mbbls/d)	448	456	438	464	435	457	465	484	421	457

(2) Represents 100% of the Wood River and Borger refinery operations.

Operating Statistics – Netbacks (unaudited)

Operating Statistics – After Royalties (continued)

Per-Unit Results

(excluding impact of realized financial hedging)

2008

2007

	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Produced Gas										
– Canadian Plains (\$/Mcf)										
Price	7.77	5.65	8.67	9.50	7.19	6.10	6.21	5.26	6.66	6.25
Production and mineral taxes	0.12	0.06	0.17	0.17	0.06	0.11	0.04	0.13	0.14	0.12
Transportation and selling	0.23	0.21	0.24	0.22	0.25	0.26	0.25	0.25	0.26	0.27
Operating	0.78	0.65	0.59	0.96	0.93	0.69	0.81	0.62	0.69	0.65
Netback	6.64	4.73	7.67	8.15	5.95	5.04	5.11	4.26	5.57	5.21
Produced Gas										
– Canadian Foothills (\$/Mcf)										
Price	8.12	5.87	9.03	9.94	7.61	6.30	6.44	5.46	6.86	6.46
Production and mineral taxes	0.06	0.03	0.09	0.09	0.03	0.08	0.04	0.08	0.11	0.10
Transportation and selling	0.42	0.37	0.43	0.43	0.47	0.42	0.41	0.41	0.43	0.43
Operating	1.15	0.98	0.87	1.39	1.41	1.05	1.14	0.96	1.02	1.09
Netback	6.49	4.49	7.64	8.03	5.70	4.75	4.85	4.01	5.30	4.84
Produced Gas – Canada (\$/Mcf)										
Price	7.97	5.78	8.88	9.76	7.44	6.20	6.35	5.36	6.76	6.36
Production and mineral taxes	0.08	0.04	0.12	0.12	0.04	0.09	0.03	0.10	0.11	0.10
Transportation and selling	0.35	0.31	0.36	0.35	0.38	0.35	0.35	0.34	0.36	0.36
Operating	1.03	0.87	0.77	1.23	1.25	0.92	1.03	0.83	0.90	0.91
Netback	6.51	4.56	7.63	8.06	5.77	4.84	4.94	4.09	5.39	4.99
Produced Gas – USA (\$/Mcf)										
Price	7.89	5.01	8.54	9.93	8.19	5.38	5.03	4.68	5.73	6.24
Production and mineral taxes	0.56	0.35	0.56	0.72	0.62	0.34	0.29	0.38	0.17	0.53
Transportation and selling	0.84	0.87	0.86	0.81	0.81	0.62	0.64	0.60	0.65	0.61
Operating	0.59	0.56	0.38	0.71	0.71	0.65	0.70	0.52	0.71	0.67
Netback	5.90	3.23	6.74	7.69	6.05	3.77	3.40	3.18	4.20	4.43
Produced Gas – Total (\$/Mcf)										
Price	7.94	5.44	8.74	9.83	7.75	5.89	5.83	5.10	6.38	6.32
Production and mineral taxes	0.28	0.17	0.31	0.37	0.28	0.18	0.14	0.21	0.14	0.26
Transportation and selling	0.56	0.55	0.57	0.55	0.56	0.45	0.46	0.44	0.47	0.45
Operating	0.84	0.74	0.61	1.01	1.02	0.82	0.90	0.72	0.83	0.82
Netback	6.26	3.98	7.25	7.90	5.89	4.44	4.33	3.73	4.94	4.79
Natural Gas Liquids										
– Canadian Plains (\$/bbl)										
Price	78.91	45.13	98.35	96.34	75.09	59.98	73.12	61.29	56.08	46.69
Production and mineral taxes	–	–	–	–	–	–	–	–	–	–
Transportation and selling	–	–	0.01	–	–	–	–	–	–	–
Netback	78.91	45.13	98.34	96.34	75.09	59.98	73.12	61.29	56.08	46.69

Operating Statistics – Netbacks (unaudited)

Operating Statistics – After Royalties (continued)

Per-unit Results

(excluding impact of realized financial hedging)

2008

2007

	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Natural Gas Liquids										
– Canadian Foothills (\$/bbl)										
Price	80.22	42.03	95.49	101.23	80.80	59.26	73.42	63.06	55.10	42.82
Production and mineral taxes	–	–	–	–	–	–	–	–	–	–
Transportation and selling	1.33	1.33	1.20	1.73	1.04	1.14	1.08	2.02	0.83	0.61
Netback	78.89	40.70	94.29	99.50	79.76	58.12	72.34	61.04	54.27	42.21
Natural Gas Liquids – Canada (\$/bbl)										
Price	80.10	42.31	95.74	100.78	80.23	59.34	73.39	62.87	55.21	43.26
Production and mineral taxes	–	–	–	–	–	–	–	–	–	–
Transportation and selling	1.21	1.21	1.10	1.57	0.94	1.01	0.96	1.80	0.74	0.54
Netback	78.89	41.10	94.64	99.21	79.29	58.33	72.43	61.07	54.47	42.72
Natural Gas Liquids – USA ⁽¹⁾ (\$/bbl)										
Price	83.18	45.39	97.63	105.73	82.22	59.83	73.45	60.17	55.43	47.77
Production and mineral taxes	7.25	3.79	8.19	9.75	7.13	4.28	6.12	1.95	4.71	4.56
Transportation and selling	–	–	–	–	–	0.01	–	0.01	0.01	0.01
Netback	75.93	41.60	89.44	95.98	75.09	55.54	67.33	58.21	50.71	43.20
Natural Gas Liquids – Total (\$/bbl)										
Price	81.67	43.88	96.72	103.29	81.24	59.61	73.42	61.31	55.33	45.66
Production and mineral taxes	3.70	1.93	4.25	4.94	3.63	2.36	3.30	1.13	2.59	2.43
Transportation and selling	0.59	0.59	0.53	0.78	0.46	0.46	0.44	0.76	0.34	0.26
Netback	77.38	41.36	91.94	97.57	77.15	56.79	69.68	59.42	52.40	42.97
Crude Oil – Light and Medium										
– Canadian Plains (\$/bbl)										
Price	84.84	41.60	107.59	107.08	85.90	56.41	68.78	59.68	52.43	44.81
Production and mineral taxes	3.33	2.05	4.70	3.97	2.72	2.37	2.36	2.16	2.37	2.59
Transportation and selling	1.20	0.96	1.41	1.27	1.16	1.33	1.22	1.39	1.27	1.43
Operating	10.56	8.28	9.40	13.05	11.60	9.20	10.34	8.84	9.10	8.55
Netback	69.75	30.31	92.08	88.79	70.42	43.51	54.86	47.29	39.69	32.24
Crude Oil – Light and Medium										
– Canadian Foothills (\$/bbl)										
Price	91.78	47.51	112.73	114.28	93.42	64.63	81.51	67.07	57.00	52.31
Production and mineral taxes	1.48	1.11	1.65	2.05	1.16	1.05	1.59	0.76	1.47	0.37
Transportation and selling	2.07	1.55	2.12	2.70	1.92	1.77	1.66	2.16	1.79	1.49
Operating	12.75	11.68	10.02	15.39	13.84	10.84	12.72	11.21	9.31	10.03
Netback	75.48	33.17	98.94	94.14	76.50	50.97	65.54	52.94	44.43	40.42

(1) The Natural Gas Liquids – USA netback is equivalent to the Total Liquids – USA netback.

Operating Statistics – Netbacks (unaudited)

Operating Statistics – After Royalties (continued)

Per-unit Results

(excluding impact of realized financial hedging)

	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Crude Oil – Heavy										
– Canadian Plains (\$/bbl)										
Price	74.08	31.30	95.86	98.65	70.44	43.91	49.52	48.22	40.70	37.22
Production and mineral taxes	0.03	0.06	0.07	(0.10)	0.07	0.05	0.07	0.06	0.06	(0.01)
Transportation and selling	1.60	1.13	2.42	1.60	1.29	1.18	1.13	1.36	1.19	1.03
Operating	9.04	7.17	7.62	11.30	9.93	7.59	9.06	7.27	7.56	6.48
Netback	63.41	22.94	85.75	85.85	59.15	35.09	39.26	39.53	31.89	29.72
Crude Oil – Total – excluding Foster Creek/Christina Lake (\$/bbl)										
Price	80.31	37.20	102.66	103.40	78.82	50.76	59.93	54.68	47.02	41.42
Production and mineral taxes	1.56	1.02	2.16	1.81	1.28	1.09	1.12	1.01	1.16	1.06
Transportation and selling	1.52	1.13	2.00	1.61	1.36	1.32	1.23	1.47	1.31	1.27
Operating	10.43	8.28	8.99	13.00	11.39	9.03	10.52	8.68	8.85	8.06
Netback	66.80	26.77	89.51	86.98	64.79	39.32	47.06	43.52	35.70	31.03
Crude Oil – Heavy – Foster Creek/Christina Lake (\$/bbl)										
Price ⁽²⁾	62.44	19.86	91.21	93.64	59.67	40.14	45.58	42.86	39.40	33.28
Production and mineral taxes	–	–	–	–	–	–	–	–	–	–
Transportation and selling	2.36	2.04	2.10	2.77	2.72	2.88	2.75	2.10	3.62	3.07
Operating ⁽³⁾	15.53	10.73	15.53	21.41	16.62	14.46	14.05	12.55	14.02	17.12
Netback	44.55	7.09	73.58	69.46	40.33	22.80	28.78	28.21	21.76	13.09
Crude Oil – Total ⁽⁴⁾ (\$/bbl)										
Price	75.36	31.58	99.39	100.99	74.10	47.90	56.23	51.50	44.92	39.19
Production and mineral taxes	1.13	0.69	1.54	1.36	0.96	0.79	0.83	0.74	0.84	0.77
Transportation and selling	1.75	1.43	2.03	1.90	1.69	1.74	1.62	1.64	1.94	1.75
Operating	11.84	9.08	10.86	15.08	12.68	10.49	11.43	9.72	10.27	10.54
Netback	60.64	20.38	84.96	82.65	58.77	34.88	42.35	39.40	31.87	26.13

(2) 2008 price includes the impact of the write-down of condensate inventories to net realizable value (2008 – \$4.26/bbl; Q4 2008 – \$11.21/bbl; Q3 2008 – \$3.07/bbl).

(3) Q1 2007 includes a prior year under accrual of operating costs of approximately \$1.82/bbl.

(4) The Crude Oil – Total netback is equivalent to the Crude Oil – Canada netback.

Operating Statistics – Netbacks (unaudited)

Operating Statistics – After Royalties (continued)

Per-unit Results

(excluding impact of realized financial hedging)

	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Total Liquids – Canada (\$/bbl)										
Price	75.85	32.63	98.99	100.97	74.69	48.92	57.92	52.50	45.83	39.50
Production and mineral taxes	1.01	0.62	1.37	1.20	0.86	0.72	0.74	0.66	0.76	0.70
Transportation and selling	1.70	1.41	1.93	1.86	1.62	1.68	1.56	1.66	1.84	1.67
Operating	10.57	8.19	9.68	13.34	11.30	9.47	10.20	8.78	9.29	9.60
Netback	62.57	22.41	86.01	84.57	60.91	37.05	45.42	41.40	33.94	27.53
Total Liquids (\$/bbl)										
Price	76.58	33.81	98.85	101.46	75.44	50.05	59.60	53.37	46.81	40.25
Production and mineral taxes	1.63	0.92	2.09	2.09	1.46	1.08	1.32	0.81	1.16	1.04
Transportation and selling	1.53	1.28	1.72	1.67	1.46	1.51	1.39	1.47	1.65	1.51
Operating	9.55	7.43	8.66	12.00	10.30	8.57	9.19	7.87	8.41	8.81
Netback	63.87	24.18	86.38	85.70	62.22	38.89	47.70	43.22	35.59	28.89
Total (\$/Mcfe)										
Price	8.77	5.48	10.04	11.02	8.61	6.35	6.57	5.80	6.65	6.40
Production and mineral taxes	0.28	0.17	0.32	0.37	0.28	0.18	0.15	0.19	0.15	0.24
Transportation and selling	0.50	0.49	0.53	0.50	0.50	0.42	0.42	0.41	0.43	0.42
Operating ⁽⁵⁾	0.97	0.83	0.75	1.17	1.15	0.93	1.02	0.83	0.93	0.95
Netback	7.02	3.99	8.44	8.98	6.68	4.82	4.98	4.37	5.14	4.79

(5) 2008 operating costs include a recovery of costs related to long-term incentives of \$0.01/Mcfe (2007 – costs of \$0.05/Mcfe).

Impact of Realized Financial Hedging

	2008	2007								
Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1	
Natural Gas (\$/Mcf)	(0.02)	1.74	(0.80)	(1.29)	0.27	1.33	1.49	1.65	1.24	0.92
Liquids (\$/bbl)	(5.46)	2.35	(7.97)	(10.99)	(5.85)	(3.05)	(8.76)	(4.36)	(1.34)	2.34
Total (\$/Mcfe)	(0.17)	1.50	(0.89)	(1.38)	0.05	0.99	0.96	1.21	0.96	0.82

Supplemental Operating Information (unaudited)

The following tables represent EnCana's and Cenovus' operating information, post-Arrangement, excluding their respective share of the Market Optimization and Corporate and Other segments. EnCana's operating divisions, post-Arrangement, would include Canadian Foothills and USA. Cenovus' operating divisions, post-Arrangement, would include Integrated Oil and Canadian Plains.

Results of Continuing Operations

	EnCana					
	Canadian Foothills		USA		Total	
For the three months ended December 31 (\$ millions)	2008	2007	2008	2007	2008	2007
Revenues, Net of Royalties	\$ 923	\$ 1,017	\$ 1,273	\$ 1,178	\$ 2,196	\$ 2,195
Expenses						
Production and mineral taxes	3	5	59	47	62	52
Transportation and selling	72	52	135	87	207	139
Operating	131	152	136	154	267	306
Operating Cash Flow	\$ 717	\$ 808	\$ 943	\$ 890	\$ 1,660	\$ 1,698

Cenovus

	Cenovus					
	Integrated Oil		Canadian Plains		Total	
For the three months ended December 31 (\$ millions)	2008	2007	2008	2007	2008	2007
Revenues, Net of Royalties	\$ 1,746	\$ 2,445	\$ 789	\$ 964	\$ 2,535	\$ 3,409
Expenses						
Production and mineral taxes	–	–	10	11	10	11
Transportation and selling	153	116	62	97	215	213
Operating	167	169	99	128	266	297
Purchased product	1,935	1,888	–	–	1,935	1,888
Operating Cash Flow	\$ (509)	\$ 272	\$ 618	\$ 728	\$ 109	\$ 1,000

Supplemental Operating Information (unaudited)

Results of Continuing Operations

	EnCana					
	Canadian Foothills		USA		Total	
For the twelve months ended December 31 (\$ millions)	2008	2007	2008	2007	2008	2007
Revenues, Net of Royalties	\$ 4,355	\$ 3,679	\$ 5,629	\$ 4,372	\$ 9,984	\$ 8,051
Expenses						
Production and mineral taxes	33	39	370	189	403	228
Transportation and selling	239	201	502	307	741	508
Operating	609	535	618	595	1,227	1,130
Operating Cash Flow	\$ 3,474	\$ 2,904	\$ 4,139	\$ 3,281	\$ 7,613	\$ 6,185

Cenovus

	Cenovus					
	Integrated Oil		Canadian Plains		Total	
For the twelve months ended December 31 (\$ millions)	2008	2007	2008	2007	2008	2007
Revenues, Net of Royalties	\$ 10,288	\$ 8,292	\$ 4,418	\$ 3,652	\$ 14,706	\$ 11,944
Expenses						
Production and mineral taxes	1	–	74	63	75	63
Transportation and selling	571	401	392	345	963	746
Operating	732	657	484	440	1,216	1,097
Purchased product	8,609	5,725	–	–	8,609	5,725
Operating Cash Flow	\$ 375	\$ 1,509	\$ 3,468	\$ 2,804	\$ 3,843	\$ 4,313

Drilling Activity (unaudited)

The following tables summarize EnCana's gross participation and net interests in wells drilled for the periods indicated.

Exploration Wells Drilled	Gas		Oil		Dry & Abandoned		Total Working Interest		Royalty		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Gross	Net	
Continuing Operations												
2008												
Canada												
Canadian Plains	5	3	1	1	2	1	8	5	34	42	5	
Canadian Foothills	70	54	8	5	—	—	78	59	69	147	59	
USA	26	14	—	—	—	—	26	14	—	26	14	
Other	—	—	—	—	3	1	3	1	—	3	1	
Total	101	71	9	6	5	2	115	79	103	218	79	
2007												
Canada												
Canadian Plains	4	4	3	3	—	—	7	7	89	96	7	
Canadian Foothills	116	92	4	3	—	—	120	95	91	211	95	
USA	2	2	—	—	—	—	2	2	—	2	2	
Other	—	—	—	—	4	3	4	3	—	4	3	
Total	122	98	7	6	4	3	133	107	180	313	107	
2006												
Canada												
Canadian Plains	19	18	2	2	—	—	21	20	108	129	20	
Canadian Foothills	262	212	5	5	7	6	274	223	20	294	223	
USA	12	7	—	—	2	1	14	8	—	14	8	
Other	—	—	2	1	4	1	6	2	—	6	2	
Total	293	237	9	8	13	8	315	253	128	443	253	

Drilling Activity (unaudited)

Development Wells Drilled	Gas		Oil		Dry & Abandoned		Total Working Interest		Royalty		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Gross	Gross	Net
Continuing Operations												
2008												
Canada												
Canadian Plains	1,489	1,372	105	92	7	7	1,601	1,471	503	2,104	2,104	1,471
Canadian Foothills	1,088	989	17	16	—	—	1,105	1,005	329	1,434	1,434	1,005
Integrated Oil – Canada	13	13	41	21	4	4	58	38	41	99	99	38
USA	904	736	—	—	—	—	904	736	378	1,282	1,282	736
Total	3,494	3,110	163	129	11	11	3,668	3,250	1,251	4,919	4,919	3,250
2007												
Canada												
Canadian Plains	2,215	2,115	161	138	4	3	2,380	2,256	466	2,846	2,846	2,256
Canadian Foothills	1,528	1,425	20	18	1	1	1,549	1,444	325	1,874	1,874	1,444
Integrated Oil – Canada	6	2	55	29	6	4	67	35	43	110	110	35
USA	809	641	—	—	1	1	810	642	36	846	846	642
Total	4,558	4,183	236	185	12	9	4,806	4,377	870	5,676	5,676	4,377
2006												
Canada												
Canadian Plains	1,546	1,525	118	88	1	1	1,665	1,614	822	2,487	2,487	1,614
Canadian Foothills	1,187	1,048	13	7	—	—	1,200	1,055	32	1,232	1,232	1,055
Integrated Oil – Canada	66	66	8	8	24	23	98	97	1	99	99	97
USA	779	625	—	—	7	6	786	631	22	808	808	631
Total	3,578	3,264	139	103	32	30	3,749	3,397	877	4,626	4,626	3,397
Discontinued Operations												
Ecuador – 2006	—	—	7	6	1	1	8	7	—	8	8	7

(1) "Gross" wells are the total number of wells in which EnCana has an interest.

(2) "Net" wells are the number of wells obtained by aggregating EnCana's working interest in each of its gross wells.

(3) At December 31, 2008, EnCana was in the process of drilling 26 gross wells (19 net wells) in Canada, 47 gross wells (38 net wells) in the U.S.

Land (unaudited)

The following table summarizes EnCana's interest in producing wells and wells capable of producing as at December 31, 2008.

Location of Wells	Gas		Oil		Total	
	Gross	Net	Gross	Net	Gross	Net
Alberta	40,458	38,224	4,032	3,567	44,490	41,791
British Columbia	2,023	1,894	17	12	2,040	1,906
Saskatchewan	452	419	917	600	1,369	1,019
Manitoba	-	-	1	1	1	1
Total Canada	42,933	40,537	4,967	4,180	47,900	44,717
Colorado	4,741	4,159	6	2	4,747	4,161
Texas	1,741	1,213	40	29	1,781	1,242
Wyoming	2,151	1,488	4	3	2,155	1,491
Utah	35	31	12	12	47	43
Louisiana	27	18	-	-	27	18
Kansas	1	1	-	-	1	1
Montana	1	1	-	-	1	1
Total United States	8,697	6,911	62	46	8,759	6,957
Total	51,630	47,448	5,029	4,226	56,659	51,674

(1) EnCana has varying royalty interests in 16,437 natural gas wells and 10,364 crude oil wells which are producing or capable of producing.

(2) Includes wells containing multiple completions as follows: 34,582 gross natural gas wells (32,807 net wells) and 1,498 gross crude oil wells (1,345 net wells).

The following table summarizes EnCana's developed, undeveloped and total landholdings as at December 31, 2008.

Interest in Material Properties	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Canada						
Alberta						
Fee	4,524	4,524	2,258	2,258	6,782	6,782
Crown	4,130	3,213	4,148	3,251	8,278	6,464
Freehold	275	164	163	141	438	305
	8,929	7,901	6,569	5,650	15,498	13,551
British Columbia						
Crown	1,005	901	3,095	2,533	4,100	3,434
Freehold	-	-	7	-	7	-
	1,005	901	3,102	2,533	4,107	3,434
Saskatchewan						
Fee	64	64	447	447	511	511
Crown	133	111	410	352	543	463
Freehold	14	10	48	46	62	56
	211	185	905	845	1,116	1,030
Manitoba – Fee	3	3	261	261	264	264
Newfoundland and Labrador – Crown	-	-	35	2	35	2
Nova Scotia – Crown	-	-	41	29	41	29
Northwest Territories – Crown	-	-	45	12	45	12
Total Canada	10,148	8,990	10,958	9,332	21,106	18,322

Land (unaudited)

Interest in Material Properties (continued)		Developed		Undeveloped		Total	
		Gross	Net	Gross	Net	Gross	Net
United States							
Colorado							
Federal/State Lands		199	184	668	614	867	798
Freehold		102	93	166	153	268	246
Fee		1	1	4	4	5	5
		302	278	838	771	1,140	1,049
Texas							
Federal/State Lands		12	7	460	441	472	448
Freehold		227	166	1,091	873	1,318	1,039
Fee		—	—	4	2	4	2
		239	173	1,555	1,316	1,794	1,489
Wyoming							
Federal/State Lands		137	82	546	393	683	475
Freehold		17	10	31	16	48	26
		154	92	577	409	731	501
Other							
Federal/State Lands		8	7	360	220	368	227
Freehold		12	10	1,257	1,062	1,269	1,072
Fee		—	—	87	87	87	87
		20	17	1,704	1,369	1,724	1,386
Total United States		715	560	4,674	3,865	5,389	4,425
International							
Greenland		—	—	1,700	808	1,700	808
Azerbaijan		—	—	346	17	346	17
Australia		—	—	104	40	104	40
Qatar ⁽⁷⁾		—	—	—	—	—	—
Brazil ⁽⁸⁾		—	—	—	—	—	—
France ⁽⁹⁾		—	—	—	—	—	—
Total International		—	—	2,150	865	2,150	865
Total		10,863	9,550	17,782	14,062	28,645	23,612

- (1) This table excludes approximately 4.9 million gross acres under lease or sublease, reserving to EnCana royalties or other interests.
- (2) Fee lands are those lands in which EnCana has a fee simple interest in the minerals rights and has either: (i) not leased out all of the mineral zones; or (ii) retained a working interest. The current fee lands acreage summary now includes all fee titles owned by EnCana that have one or more zones that remain unleased or available for development.
- (3) Crown/Federal/State lands are those owned by the federal, provincial, or state government or the First Nations, in which EnCana has purchased a working interest lease.
- (4) Freehold lands are owned by individuals (other than a government or EnCana), in which EnCana holds a working interest lease.
- (5) Gross acres are the total area of properties in which EnCana has an interest.
- (6) Net acres are the sum of EnCana's fractional interest in gross acres.
- (7) In October 2008, EnCana relinquished its interests in Qatar.
- (8) In September 2008, EnCana sold its remaining interests in Brazil.
- (9) In December 2008, EnCana completed the sale of all of its interests in France.

Corporate Information

CORPORATE OFFICERS ⁽¹⁾

Randall K. Eresman
President & Chief Executive Officer

John K. Brannan
Executive Vice-President
(*President, Integrated Oil Division*)

Sherri A. Brillon
Executive Vice-President, Strategic
Planning & Portfolio Management

Brian C. Ferguson
Executive Vice-President
& Chief Financial Officer

Kerry D. Dyte
Vice-President, General Counsel
& Corporate Secretary

Gerald T. Ince
Treasurer

William A. Stevenson
Comptroller
(*Vice-President, Corporate
Finance Group*)

Michael M. Graham
Executive Vice-President
(*President, Canadian Foothills Division*)

Sheila M. McIntosh
Executive Vice-President,
Corporate Communications

R. William Oliver
Executive Vice-President,
Business Development,
Canadian Gas Marketing and Power

Gerard J. Prott
Executive Vice-President,
Corporate Relations

Ivor M. Ruste
Executive Vice-President
& Chief Risk Officer

Donald T. Swystun
Executive Vice-President
(*President, Canadian Plains Division*)

Hayward J. Walls
Executive Vice-President,
Corporate Services

Jeff E. Wojahn
Executive Vice-President
(*President, USA Division*)

(1) Divisional title in italics.

BOARD OF DIRECTORS

David P. O'Brien, O.C. ⁽¹⁾⁽⁵⁾⁽⁷⁾
Chairman of the Board
Calgary, Alberta

Ralph S. Cunningham ⁽³⁾⁽⁴⁾⁽⁶⁾
Houston, Texas

Patrick D. Daniel ⁽²⁾⁽⁵⁾⁽⁶⁾
Calgary, Alberta

Ian W. Delaney ⁽⁴⁾⁽⁵⁾⁽⁶⁾
Toronto, Ontario

Randall K. Eresman ⁽⁷⁾⁽⁸⁾
Calgary, Alberta

Claire S. Farley ⁽³⁾⁽⁶⁾⁽⁷⁾
Houston, Texas

Michael A. Grandin ⁽⁴⁾⁽⁵⁾⁽⁶⁾⁽⁸⁾
Calgary, Alberta

Barry W. Harrison ⁽²⁾⁽⁵⁾⁽⁷⁾
Calgary, Alberta

Dale A. Lucas ⁽²⁾⁽⁴⁾⁽⁷⁾
Calgary, Alberta

Valerie A. A. Nielsen ⁽³⁾⁽⁶⁾⁽⁸⁾
Calgary, Alberta

Jane L. Peverett ⁽²⁾⁽⁴⁾⁽⁷⁾
West Vancouver, British Columbia

Allan P. Sawin ⁽²⁾⁽⁴⁾⁽⁷⁾
Edmonton, Alberta

James M. Stanford, O.C. ⁽²⁾⁽⁶⁾⁽⁸⁾
Calgary, Alberta

Wayne G. Thomson ⁽³⁾⁽⁶⁾⁽⁸⁾
Calgary, Alberta

Clayton H. Woitas ⁽³⁾⁽⁶⁾⁽⁷⁾
Calgary, Alberta

(1) Chairman of the Board, Chairman of Nominating and Corporate Governance Committee, Chairman of GasCo Committee, and ex officio member of other Board Committees (2)(3)(4)(5)(6)

(2) Audit Committee

(3) Corporate Responsibility, Environment, Health and Safety Committee

(4) Human Resources and Compensation Committee

(5) Nominating and Corporate Governance Committee

(6) Reserves Committee

(7) GasCo Committee *

(8) Cenovus Committee *

* On June 4, 2008, the Board of Directors created the GasCo and Cenovus Committees which are charged with the oversight of strategic planning, governance and other matters related to each of the two separate public entities that would result from the proposed corporate reorganization announced on May 11, 2008.

ENCANA HEAD OFFICE

1800, 855 – 2nd Street S.W.
P.O. Box 2850
Calgary, Alberta, Canada T2P 2S5
Phone: 403-645-2000
www.encana.com

Corporate Information

TRANSFER AGENTS & REGISTRAR

Common Shares

CIBC Mellon Trust Company

Calgary, Montreal & Toronto

BNY Mellon Shareowner Services

Jersey City, New Jersey

Shareholders are encouraged to contact CIBC Mellon Trust Company for information regarding their security holdings. They can be reached via the Answerline at 416-643-5500 or toll-free throughout North America at 1-800-387-0825, or via facsimile at 416-643-5501.

Mailing address

CIBC Mellon Trust Company

P.O. Box 7010

Adelaide Street Postal Station

Toronto, Ontario, Canada M5C 2W9

Internet address

www.cibcmellon.com

TRUSTEE & REGISTRARS

CIBC Mellon Trust Company

Canadian Medium Term Notes

Calgary, Alberta

Toronto, Ontario

The Bank of New York

4.600% Senior Notes

4.750% Senior Notes

5.900% Senior Notes

6.500% Senior Notes

6.500% Senior Notes

6.625% Senior Notes

7.375% Senior Notes

7.650% Senior Notes

8.125% Senior Notes

New York, New York

The Bank of Nova Scotia

Trust Company of New York

6.30% Senior Notes

7.20% Senior Notes

New York, New York

Deutsche Bank Trust Company Americas

5.80% Senior Notes

(EnCana Holdings Finance Corp.)

New York, New York

AUDITORS

PricewaterhouseCoopers LLP

Chartered Accountants

Calgary, Alberta

INDEPENDENT QUALIFIED RESERVE EVALUATORS

DeGolyer and MacNaughton

Dallas, Texas

GLJ Petroleum Consultants Ltd.

Calgary, Alberta

McDaniel & Associates Consultants Ltd.

Calgary, Alberta

Netherland, Sewell & Associates, Inc.

Dallas, Texas

STOCK EXCHANGES

Common Shares (ECA)

Toronto Stock Exchange

New York Stock Exchange

PRINCIPAL OPERATING SUBSIDIARIES & PARTNERSHIPS

	Percent Owned ⁽¹⁾
EnCana Marketing (USA) Inc.	100
EnCana Oil & Gas (USA) Inc.	100
EnCana Oil & Gas Partnership	100
FCCL Oil Sands Partnership	50
WRB Refining LLC	50

(1) Includes indirect ownership.

The above is not a complete list of all of the subsidiaries and partnerships of EnCana Corporation.

Investor Information

ANNUAL MEETING

Shareholders are invited to attend the Annual Meeting being held on Wednesday, April 22, 2009 at 2 p.m. local time at the Calgary TELUS Convention Centre

Exhibition Hall E, 2nd Floor, North Building
136 – 8 Avenue S.E.
Calgary, Alberta, Canada

Those unable to do so are asked to sign and return the form of proxy that has been mailed to them.

ANNUAL INFORMATION FORM (FORM 40-F)

EnCana's Annual Information Form (AIF) is filed with the securities regulators in Canada and the United States. Under the Multi-Jurisdictional Disclosure System, EnCana's AIF is filed as Form 40-F with the U.S. Securities and Exchange Commission.

SHAREHOLDER ACCOUNT MATTERS

To change your address, transfer shares, eliminate duplicate mailings, have dividends deposited directly into accounts at financial institutions in Canada that provide electronic fund-transfer services, etc., please contact CIBC Mellon Trust Company.

ENCANA WEBSITE

www.encana.com

EnCana's website contains a variety of corporate and investor information including, among other information, the following:

- Current stock prices
- Annual and Interim Reports
- Information Circular
- News releases
- Investor presentations
- Dividend information
- Dividend reinvestment plan
- Shareholder support information
- Corporate Responsibility Report

Additional information, including copies of the 2008 EnCana Corporation Annual Report, may be obtained from:

EnCana Corporation
Investor Relations,
Corporate Communications
1800, 855 – 2nd Street S.W.
P.O. Box 2850
Calgary, Alberta, Canada T2P 2S5
Phone: 403-645-3550
investor.relations@encana.com
www.encana.com

Investor inquiries should be directed to:

Paul Gagne
Vice-President, Investor Relations
403-645-4737
paul.gagne@encana.com

Susan Grey
Manager, Investor Relations
403-645-4751
susan.grey@encana.com

Ryder McRitchie
Manager, Investor Relations
403-645-2007
ryder.mcritchie@encana.com

Media inquiries should be directed to:

Alan Boras
Manager, Media Relations
403-645-4747
alan.boras@encana.com

ABBREVIATIONS

bbls	barrels
Bcf	billion cubic feet
Bcfe	billion cubic feet equivalent
CBM	coalbed methane
CO₂	carbon dioxide
EBITDA	earnings before interest, taxes, depreciation and amortization
Mbbls	thousand barrels
MMbbls	million barrels
Mcfc	thousand cubic feet
Mcfe	thousand cubic feet equivalent
MM	million
MMcf	million cubic feet
MMcfe	million cubic feet equivalent
NGLs	natural gas liquids
NOx	nitrogen oxide
SAGD	steam-assisted gravity drainage
SO₂	sulphur dioxide
Tcf	trillion cubic feet
Tcfe	trillion cubic feet equivalent
/d	per day



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EnCana Corporation
1800, 855 – 2nd Street S.W.
P.O. Box 2850
Calgary, Alberta, Canada T2P 2S5
Phone: 403-645-2000
www.encana.com

